APPENDIX E

PHMSA Enclosure B

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The purpose of Enclosure B is to augment the National Environmental Policy Act analysis presented in the Donlin Gold Project Draft Environmental Impact Statement (EIS) with information that meets specific U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements for a special permit as described in 49 Code of Federal Regulations (CFR) § 190.341. The Draft Special Permit for usage of strain-based design and this Enclosure B are included together as an Appendix to the Donlin Gold EIS currently being prepared by the U.S. Army Corps of Engineers (USACE).

I. Purpose and Need

Donlin Gold LLC (Donlin Gold) is proposing to build a pipeline to transport natural gas to the mine site. PHMSA is the regulating agency and 49 CFR Part 192 includes specific regulatory requirements for the design, construction, operation, and maintenance of natural gas pipelines to maintain safety. Donlin Gold anticipates there will be areas along the pipeline with potentially frost unstable soils or ground movement, and intends to request a Special Permit from PHMSA to allow Strain-Based Design of this segment of the pipeline. Strain-Based Design (SBD) involves advanced metallurgy and engineering to allow the pipe to deform in the longitudinal direction and better maintain its integrity and safety. PHMSA issues special permits only when consistent with pipeline safety. PHMSA imposes conditions on the grant of special permits to assure safety and environmental protection in accordance with 49 CFR § 190.341. PHMSA is required to comply with the National Environmental Policy Act (NEPA) in deciding whether to issue the special permit.

A Special Permit would allow Donlin Gold to design and construct the pipeline using Strain-Based Design. The Special Permit would include conditions to ensure the pipeline has equal or greater safety than a pipeline constructed in accordance with 49 CFR Part 192.

II. Background and Site Description

Figure 1 shows the pipeline route from Cook Inlet to the Donlin Gold project site located approximately 10 miles north of the village of Crooked Creek on the Kuskokwim River. The pipeline crosses a mix of lands administered by the State of Alaska, the Bureau of Land Management, and private lands, as shown in Figure 1.

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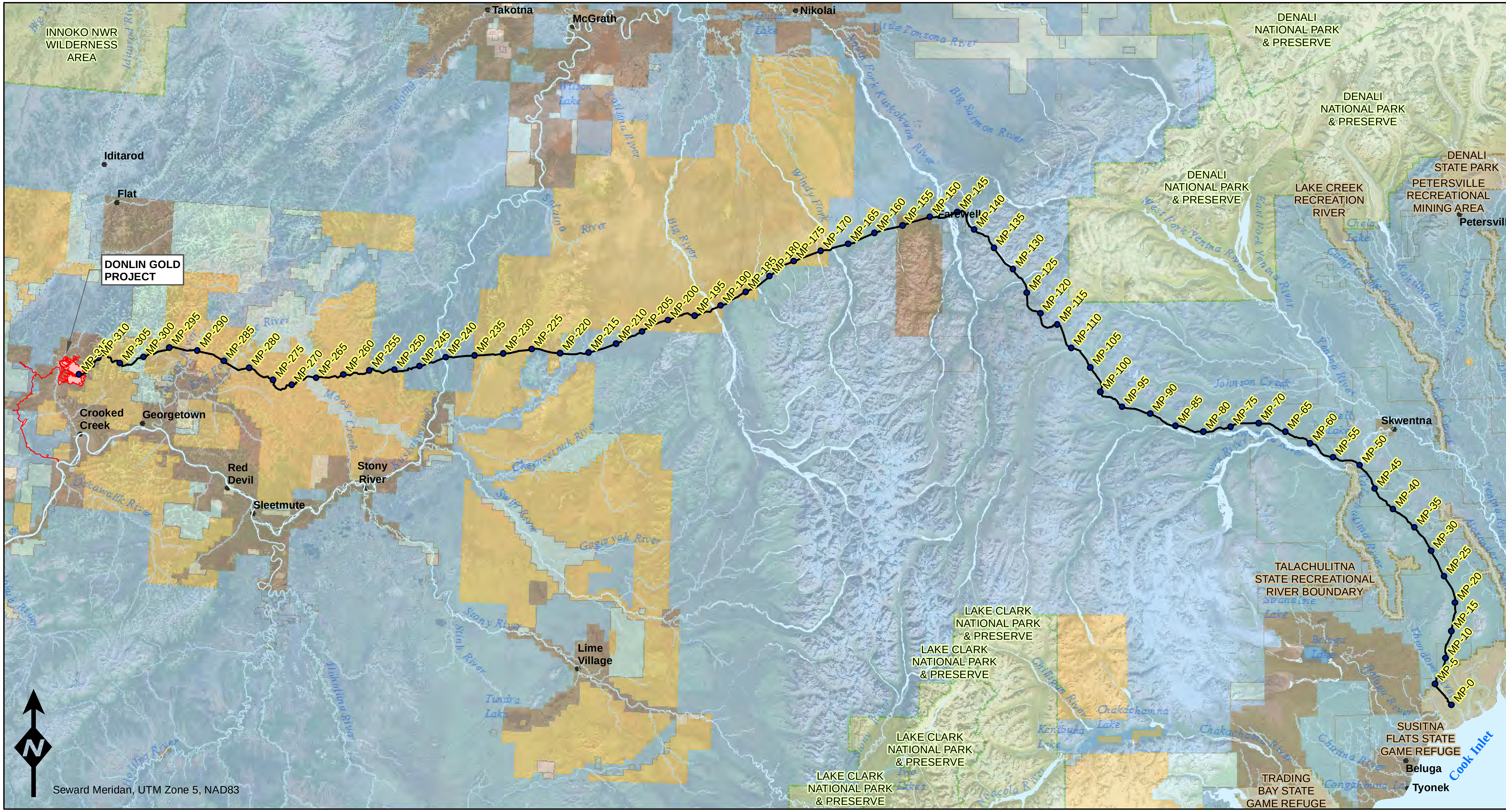

Proposed Facilities

- Proposed Natural Gas Pipeline Milepost (MP-)
- Proposed Natural Gas Pipeline Alignment
- Proposed Facilities

Land Status Details

- Bureau of Land Management
- Fish and Wildlife Service
- Military
- National Park Service
- Native Patent or IC
- Native Selected (BLM)
- Private
- State Patent or TA
- State Selected (BLM)
- Federal Administrative Boundary
- State Administrative Boundary

DONLIN GOLD

PROPOSED NATURAL GAS PIPELINE DESIGN

DONLIN GOLD PROJECT

SCALE: 0 5 10 20 mi; 0 7.5 15 30 km

FIGURE: 1

DG: ENG0235.mxd, 08/12/15, R01

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The proposed pipeline would be approximately 315 miles long (507 km), would originate at the west end of the Beluga Gas Field, approximately 30 miles (48 km) northwest of Anchorage at a tie-in near Beluga located in the Matanuska-Susitna Borough, and would run to the Donlin Gold mine. The pipeline route begins at the Beluga Natural Gas Pipeline (BPL) (the natural gas source), designated Mile Post (MP) 0 within the Susitna Flats State Game Refuge (SFSGR) and follows the Pretty Creek public road easement for most of the pipeline's route though the SFSGR. The gas would receive booster compression supplied by one compressor station located at approximately MP 0.4 near the beginning of the pipeline. No additional compression along the pipeline route would be required. From the SFSGR the route then proceeds north, traversing the east flank of Little Mount Susitna to the Skwentna River (approximately MP 50), and then parallels the Skwentna River westerly to Puntilla Lake (approximately MP 102).

From approximately MP 106 the route trends northwest to a crossing of the Happy River at approximately MP 108.5. From the Happy River crossing, the pipeline route proceeds along a low moraine ridge before turning north into the broad valley of Three Mile Creek. At approximately MP 114.5 the alignment trends westerly as it approaches the unnamed pass in the Alaska Range divide. This pass has an elevation of 3,870 feet (1,179.6 m). The short steep drainages immediately on each side of the pass are in narrow valleys with talus lobes and stabilized rock glaciers at the base of steep rock slopes. Here the pipeline utilizes benches above the creeks that flow from the pass. At approximately MP 120.5 the pipeline route enters a typical broad "U shaped" valley characteristic of the glacial valleys in this region. As the pipeline route descends this valley it is typically on the benches or terraces with moderate to little slope that border this unnamed tributary of the Tatina River.

At approximately MP 127.3, the realignment crosses the Tatina River's glacial braided floodplain before it ascends to a broad open pass before descending into the valley of the Jones River at approximately MP 130.5. From approximately MP 130.5 to MP 143 the pipeline route remains in the Jones River Valley and roughly parallels the Jones River. The route crosses the Jones River twice at approximately MP 136.6 and MP 137.6. The pipeline route exits the mountains of the Alaska Range and crosses the Denali Fault at approximately MP 149 heading westerly crossing the South Fork of the Kuskokwim River then trending southwesterly towards Farewell.

The route continues southwest near Farewell (approximately MP 157), paralleling the Alaska Range until crossing the Kuskokwim River (between approximately MP 240 and MP 241). Beyond the Kuskokwim River, the route primarily follows ridgelines for more

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than 80 miles (129 km) toward the west, to the proposed Donlin Gold mine site, the pipeline terminus, at approximately MP 315, about 10 miles (16 km) north of the village of Crooked Creek.

With the exception of the first five miles where the pipeline parallels an oilfield service road, the route does not intersect or parallel any existing permanent infrastructure. From approximately mileposts 50 to 110 portions of the route parallel and occasionally intersect the Iditarod National Historic Trail (INHT) which is primarily used for winter recreational activities. Between mileposts 55 and 60 the route passes through the State of Alaska Shell Hills Subdivision (Subdivision) which consists primarily of 5 acre remote recreational parcels, most of which have not been acquired from the State and remain unused.

The entire proposed alignment is classified as Class 1 pursuant to 49 CFR § 192.5. Class 1 is defined as having 10 or fewer buildings intended for human occupancy located within 220 yards on either side of any continuous 1-mile length of pipeline. No high consequence areas as defined under 49 CFR § 192.903 have been identified.

The permanent width or size of the main proposed pipeline right-of-way (ROW) would be 50 feet (15 m) through state lands and 51 feet 2 inches (15.6 meters) through federal lands (federal ROW requires a width of 50 feet (15 m) plus the diameter of the pipeline or 51 feet 2 inches (15.6 meters). On all private land through which the proposed pipeline traverses the permanent width or size of the ROW would also be 50 feet (15.2 meters). Following the proposed pipeline alignment a nominal 100-foot (30.5 meters) wide temporary construction ROW area would be applied for in addition to the adjoining permanent 50 feet (15.2 meters) ROW.

The proposed gas pipeline corridor crosses four ecoregions. From east to west these areas are the Cook Inlet Basin, the Alaska Range, Tanana-Kuskokwim Lowlands, and Kuskokwim Mountains. East of the Alaska Range, mixed forest is more prevalent with coniferous forests and tundra more common west. Large concentrations of migrating waterfowl and shorebirds occupy the SFSGR. However, the absence of permafrost in that portion of the pipeline would negate the need for SBD or a special permit. A variety of songbirds and raptors inhabit the forested habitats traversed by the pipeline; furbearers include moose, caribou, Dall sheep, and black and brown bears. A detailed description of the pipeline ROW, supporting facilities, and construction methodology and facilities is provided in Section 2.3.2.3 of the Donlin Gold EIS. Baseline environmental conditions and the analysis of environmental effects resulting from construction and operation of a

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pipeline are addressed by individual resource in Chapter 3 of the Donlin Gold EIS and in Section IV of this document.

The pipeline will traverse areas potentially subject to geotechnical hazards (geohazards). Broadly defined, a geohazard is a geological and/or environmental condition with the potential to cause distress or damage to civil works. The particular geohazard of interest for the Donlin Gold pipeline is thaw settlement due to surface disturbance from construction.

Thaw settlement may occur when ground temperatures rise as a result of the disturbance of the surface vegetative mat and the ice present in the soil melts. The melting of previously permanently frozen (permafrost), ice-rich (i.e., contains ice in excess of the volume required to fill the pore space in an unfrozen state) soils results in soil consolidation or settlement, the magnitude of which is dependent on the type of soil. The amount of settlement divided by the initial thickness of the frozen soil layer is denoted as "thaw strain". Differing amounts of settlement along the alignment may then cause longitudinal bending in the pipe resulting in strains in excess of 0.5% (the pipe material's yield strength, which is defined at 0.5% strain), and thereby triggering the need to address thaw strain with the use of SBD, heavier walled pipe, or an above-ground pipeline. Soils that are only seasonally frozen (the near surface soil layers freeze during winter along the entire pipeline alignment) will not cause displacement of the bottom of the pipe ditch and thus will not affect pipe longitudinal bending.

Other geohazards such as frost heave and fault displacement, are not expected to be of concern due to the operating conditions (the pipeline will transport gas at the ambient ground temperature in the permafrost areas and therefore will not generate a permanent frost bulb around the pipe, precluding frost heave), or design/construction approach (the active fault on the alignment will be crossed via an aboveground mode designed to allow for fault displacement).

Based on soil mapping and geotechnical borings conducted by Donlin Gold the presence of permafrost in significant quantities is limited to the area from MP 100 near Puntilla Lake to MP 215 near (the Tatlawiksuk River crossing). While isolated pockets of permafrost may occur on other segments of the pipeline, Donlin Gold proposes to utilize alternative engineering and construction techniques (such as horizontal directional drilling, heavier walled pipe, or excavation of frozen material from the bottom of the ditch that is below the pipe) in these areas to mitigate the potential for high longitudinal pipe

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strains due to thaw settlement. These techniques will be in compliance with 49 CFR Part 192.

Donlin Gold and PHMSA recognize the presence of discontinuous permafrost between MP XX[1] and MP YY could potentially result in thaw settlement causing longitudinal pipe strains in excess of 0.5%. Part 192 requires that "pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation."[2] Because buried pipe in permafrost conditions would need to be exceptionally thick-walled to withstand the forces and strains due to thaw settlement, Donlin Gold is proposing to design, install and operate the pipeline between MP XX and MP YY using an SBD approach. The SBD approach would account for these strains from soil consolidation/settlement using alternative strategies, mitigation, and conditions in lieu of a heavy walled pipe. Regulatory requirements do not presently exist for the use of SBD. SBD includes factors and conditions to ensure the design and safety considerations described under 49 CFR §§ 192.103, 192.105, 192.111, 192.317, and 192.619.

III. Alternatives

An applicant requesting a Special Permit from PHMSA has the option of building a pipeline which would not require PHMSA to issue a Special Permit. This would require the design, construction, and operation of a pipeline in full compliance with Part 192 and would not be subject to longitudinal bending that result in pipe longitudinal strains above 0.5%. Therefore, PHMSA's NEPA assessment is slightly different from other agencies in that the No Action alternative is not a "no build" alternative. Rather, the No Action alternative reflects a pipeline design that would not require issuance of a Special Permit. The Proposed Action alternative reflects Donlin Gold's SBD for which a Special Permit with conditions would be issued. The two alternatives are described below.

a. No Action Alternative – Construct the pipeline using engineering and construction techniques to mitigate thaw settlement. In lieu of SBD, one or a combination of two or more of the following techniques would be employed to mitigate the thaw settlement geohazard:
   i. Removal and replacement of thaw unstable material – this technique (over excavation) would be employed only in areas where very high thaw strains in near surface soils are evident, such as massive ice directly under the ditch. The thaw-

[1] Donlin Gold and PHMSA will conduct a review to define the mileposts for the Special Permit prior to the Final EIS.
[2] 49 CFR § 192.103.

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unstable soils would be removed and replaced with imported thaw-stable materials. This would require deeper and wider trenches than would be necessary with a SBD pipeline; it would also require the mining and importation of additional select fill material to backfill the trench below the pipe and disposal of the removed material. This technique is of limited value since the magnitude of settlement required to cause high pipe strains implies a thaw depth in normal soils of over ten feet below ditch bottom.

ii. Installation of extra heavy wall pipe (~1.000-inch in thickness) – Heavy wall pipe allows the pipe to resist soil movement and conform more gradually to differential displacement of the ditch bottom. This technique could be employed in areas where the heavy wall pipe can be demonstrated to withstand strains resulting from permafrost related geohazards, and where the lateral extent of the permafrost is limited and the depth to a thaw-stable soil strata is greater than practical for complete removal and replacement of the overlaying soils or other areas considered practical.

iii. Aboveground installation – this technique requires installation of support structures to elevate the pipeline a sufficient height above the ground surface to limit thermal interaction between the pipe and the soil. This technique might be employed in areas where heavy wall pipe is not sufficient to reduce the longitudinal bending of the pipe to acceptable levels and the depth to a thaw-stable soil strata is greater than practical for complete removal and replacement of the thaw-unstable soils or in other areas considered practical. Above-ground pipeline installation is not generally favored because of visual impacts; potential disruption of animal migration/movement; safety/security concerns associated with exposed pipe; and the increased cost of installation (vertical support members).

iv. Trenchless technologies (horizontal directional drilling, horizontal boring, etc.) – this technique might be employed in areas where the lateral extent of thaw-unstable soils is limited, the strata thickness is relatively thin and well mapped, and favorable subsurface conditions for drilling exist to bore under the problematic soil strata. Although this technique could be envisioned for use in some site specific conditions, it is not a practical technique for the entire route alignment due to the expense, duration, and complexity of drilling, and the fact that not all ground conditions are amenable to drilling.

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For purposes of the impact analysis, it is assumed that substantial segments of the pipeline would be built above ground under the No Action alternative and that other methods would be implemented as practical/necessary.

b. Proposed Action Alternative – Design, construct, operate, and maintain the pipeline in compliance with the Special Permit conditions, which will ensure that the pipeline will continue to function effectively and safely, even if thaw settlement and longitudinal bending occur. The SBD Special Permit conditions will require specific materials, engineering, construction and operations and maintenance (O&M) procedures for mitigation where thaw settlement and longitudinal bending strains exceed allowed limits (0.5%) in the specified SBD segments.

i. *Explain what the special permit application asks for.*

Because PHMSA's current regulations do not address strain based design, additional conditions are warranted to address anticipated external loads and/or route hazards that could cause a pipe to move or to sustain longitudinal loads that require consideration of high strains. Such additional conditions are contemplated under 49 CFR § 192.103 and 49 CFR § 192.317. Donlin Gold requests that PHMSA issue a Special Permit to incorporate the additional conditions.

The Special Permit application covers the use of strain based design and assessment (SBDA) to address longitudinal bending of the pipe due to permanent ground deformations. For the proposed action the predominant geohazard that requires the use of SBD is thaw settlement. The pipeline would be constructed of 14-inch diameter API 5L Grade X-52 pipe with a minimum wall thickness of 0.406-inch used in all segments identified as requiring SBD. This will be significantly thicker than the minimum wall thickness required for pressure containment (0.276-inch) as calculated using the design formula for steel pipe given in 49 CFR § 192.105 for a maximum allowable operating pressure (MAOP) of 1480 pounds per square inch gauge (psig). For the No Action alternative pipe wall thickness would be driven by the thickness required for pressure containment in above ground sections and buried sections where all permafrost material has been removed from the trench, or by the thickness needed to withstand strains from permafrost related geohazards in areas where the pipe is buried in permafrost.

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The use of SBD techniques would supplement the requirements of 49 CFR Part 192, which does not address longitudinal loadings above 0.5% such as those resulting from permanent ground deformations. Since SBD is not covered by 49 CFR Part 192 or any pipeline standards, additional conditions are warranted to address these loadings.

ii. *Cite regulation(s) for which special permit is sought in accordance with 49 CFR § 190.341:*

49 C.F.R. §192.103

Donlin Gold's application for a Special Permit also addresses the following regulations:

49 CFR §§ 192.105, 192.111, 192.317 and 192.619

iii. *Explain/summarize how the design/operation/maintenance of the pipeline operating under the SP would differ from the pipeline in the no action alternative.*

In addition to applicable requirements under 49 CFR Part 192, a pipeline utilizing SBD would be subject to more rigorous materials testing, construction and O&M monitoring requirements defined in the SBD special permit conditions and specifications and procedures developed by Donlin Gold. As part of the design phase, Donlin Gold will develop Material Specifications which address the requirements of high strain behavior and perform material testing, including full scale tests, to establish tensile and compressive strain capacities for the pipeline material procured as per the developed Material Specifications. During the construction phase, Donlin Gold will complete comprehensive construction and weld procedure qualifications and non-destructive testing of all welds, and an extensive Quality Assurance and Quality Control program for pipe installation, with emphasis on girth welds, 100% nondestructive examination (NDE) of all girth welds, and records of all field welding. During the operation phase, Donlin Gold will implement comprehensive monitoring to identify potential high strain conditions and implement appropriate corrective action, as required, to ensure the safe operation of the pipeline. Additional detail on the requirements for design, construction, and operation is provided in Section VII of this document and the Draft Special Permit.

iv. ***<u>Applicant</u>*** *should include the pipeline stationing and mile posts (MP) for the location or locations of the applicable* ***special permit segment(s)***

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The Special Permit Segment for the Donlin Gold Pipeline runs from MP XX[3] to MP YY and is shown in Figure 1.

v. *Mitigation Measures*

Additional mitigation measures are addressed in Section VII of this document and the Draft Special Permit.

IV. Environmental Impacts of Proposed Action and Alternatives

a. Describe how a small and large leak/rupture to the pipeline could impact safety and the environment/human health.

i. A small leak from a buried or above ground pipeline would result in a gradual release of gas, with the total amount of gas being released dependent on the time it takes for the leak to be detected and fixed. Gas from a small leak would permeate through the backfill material (soil) before dissipating into the air or, in the case of an above ground line, dissipate directly into the air. Small gas pipeline leaks result in some impacts or loss of surrounding vegetation. This browning of vegetation can facilitate identification of small underground leaks.

ii. A large rupture would result in the rapid release of a large volume of natural gas resulting in significant damage to the pipeline would create a trench or crater in the immediate vicinity of the rupture. If an ignition source is present, an intense fire or explosion would result.

iii. For a fire resulting from a large rupture; the extent of a fire would depend on the extent of the combustible materials in the vicinity, and local environmental conditions (e.g., rain, snow cover, etc.).

iv. Comparing an aboveground pipe segment to a buried segment, extended segments of above ground pipeline increase the potential for third party and other environmental damage to the pipeline (e.g. heavy equipment or bullet strikes, avalanches etc.), while there is a lesser risk from third party damage to buried pipelines. Both options have the potential for starting a fire, once a rupture occurs. Potential corrosion and leaks may be easier to locate in aboveground segments and would be quicker and easier to repair without the need for excavation of buried pipe.

[3] Donlin Gold and PHMSA will conduct a review to define the mileposts for the Special Permit prior to the Final EIS.

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There are no measureable differences in terms of human health, safety and environmental risks related to the ability to detect potential leaks or respond to releases from a buried gas pipeline versus an above-ground pipeline in this setting

b. *Submit an explanation of **delta/difference** in safety and possible effects to the environment between the 49 CFR Part 192 baseline (Code baseline) and usage of the special permit conditions for strain based design mitigation measures.*

i. For purposes of this assessment, Donlin Gold assumes that much of the **No Action alternative would be constructed using above-ground construction techniques to address concerns related to thaw settlement in areas of permafrost.** In some areas, such as through the Three Mile Pass section, where avalanches and other geohazards are present, a mix of horizontal directional drilling (HDD) and deep excavation would most likely be utilized. In some areas, where geotechnical conditions are suitable, heavier walled pipe would be utilized. For the Proposed Action alternative the SBD segment subject to special permit conditions would be buried throughout its length, except for the crossing of the Denali Fault.

During construction, the installation of a buried pipeline under the Proposed Action alternative would require earth moving and excavation in addition to the disturbance resulting from the clearance of ROWs. These activities would result in a greater disturbance to soils compared to the No Action alternative, where the majority of the pipeline would be above-ground.

The anticipated differences in effects between the two No Action alternative and Proposed Action alternative for individual resources are discussed below.

1. Human Health and Safety

As discussed above, under the No Action alternative with an above ground pipeline leaks may be easier to locate and repair. However, Donlin believes that the presence of extensive above ground pipeline through the permafrost areas under the No Action Alternative will likely increase the potential for pipeline damage resulting from human or environmental interaction. A buried pipeline along this route is less likely to be damaged by:

- Heavy equipment being transported cross country, especially under winter whiteout conditions;

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- Intentional or unintentional bullet strikes such as happened to the Trans-Alaska Pipeline in 2001[4];
- Avalanches in the high narrow valleys of the Alaska Range Crossing.

The pipeline route through the permafrost areas is extremely remote, with human use consisting primarily of subsistence and recreational hunting and related activities. As such, the potential for people to be impacted by a gas release and potential subsequent explosion and fire is low. The above-ground aspect of the pipeline under the No Action alternative would present a greater physical threat to the safety of subsistence or other cross-country travelers who could potentially contact the pipeline under low-visibility conditions.

2. Air Quality

There would be no significant difference in emissions between the No Action and Proposed Action alternatives. The majority of heavy equipment required for construction in either alternative will be the same, including equipment such as brushers and bulldozers for the clearing and leveling of the ROW, trucks for transporting pipe, and sidebooms and welding trucks for pipe placement and welding. Above-ground portions of the No Action alternative would require additional equipment such as pile drivers for the installation of pipe supports, while below-ground portions of the No Action and the Proposed Action alternatives would require additional digging and trenching equipment. O&M activities to maintain the pipeline for the No Action and proposed Action alternatives would require similar equipment and personnel.

3. Aesthetics

The extensive above-ground pipeline under the No Action alternative presents a substantial visual impact, particularly in the vicinity of the INHT. Trail users would see the pipeline from numerous points along the trail and in some cases may need to pass under or over it. Visual effects from the buried special permit line under the Proposed Action alternative would be limited to the ROW clearance, which would be less obvious with winter snow cover.

[4] https://dec.alaska.gov/spar/ppr/docs/report/aft_comp.pdf

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The effects of a small leak are expected to be similar under both pipeline scenarios. In the event of a large rupture from an underground pipeline a crater would be created, while in the event of a rupture from aboveground pipeline damage from the rupture would be more surficial in nature. The resulting damage in either case would occur within the ROW footprint.

4. Biological Resources (including vegetation, wetlands, and wildlife)

Chapter 2 (Section 2.3.2.3) of the Donlin Gold EIS provides a detailed description of proposed pipeline construction methods. Chapter 3 of the EIS discusses impacts to soils (including permafrost [Section 3.2.3.2]), vegetation (Section 3.10.3.2), wetlands (Section 3.11.4.2), aquatic resources (Section 3.13.3.2.3) and wildlife (Section 3.12.3.2.2) resulting from the pipeline construction. No Endangered Species Act-listed species occur within the pipeline corridor (see the Donlin Gold EIS Section 3.14.2.2.2).

Construction of extensive above-ground pipeline portions of the No Action alternative would result in a similar disturbance footprint within the ROW but would require less excavation and hydrology disturbance than the buried pipeline under the proposed action.

The buried pipeline under the proposed action would generate more surface disturbance compared to above-ground pipeline under the “no action” alternative due to the excavation necessary to bury the line and in developing borrow areas for pipeline bedding. The effects of excavation from pipeline installation and borrow areas would have the largest effect in wetland areas if drainage and sub-surface flow patterns were not adequately reestablished. Construction of the above-ground portions of the No Action alternative (installation of the vertical support members) would generally have less of an adverse effect on wetland hydrology than excavation activities associated with the buried pipeline segments. Under both scenarios impacts to wetlands would be minimized by the use of winter construction techniques and route selection that minimizes wetlands construction requirements. Construction-related wetland impacts are discussed in detail in Section 3.11.4.2.3 of the EIS.

Vegetation clearing would need to occur under both alternatives, but the trench excavation under the proposed action would likely have more profound and long term impact to vegetation, especially due to hydrology disruption. ,

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The difference in the effect of a small leak would be the potential mortality for vegetation in the immediate vicinity of the leak from a buried pipeline that would not occur in an above-ground pipeline. A similar difference could also occur with wetlands. There would be no difference in effect for wildlife species. The difference in effects to vegetation, wetlands, and wildlife between and above-ground and buried pipeline would be small in the event of a large rupture. In the event of a large rupture in a buried segment of pipeline, a crater of approximately 0.1 acres could be created within the ROW; while in the event of a large rupture in an aboveground line damage would be more surficial, but also constrained to the ROW footprint. Any crater would be regraded with repair of the pipeline. The likelihood of a fire and explosion in the event of rupture are the same in both cases and the extent of adverse effects would be equally dependent on site conditions at the time of the incident.

5. Climate Change

There would be limited differences in emissions of greenhouse gases between the No Action and Proposed Action alternatives reflected primarily in the diesel emissions during construction. The No Action and Proposed Action alternatives would both require activity by fossil fuel-burning equipment for ground clearance, transportation of construction materials and employees, and stringing of the pipeline itself. The No Action alternative would require the setting of thousands of vertical support members while buried portions of the No Action and Proposed Action would require excavation equipment. When considered on a global scale the difference between emissions for the alternatives would be minimal (the Donlin Gold EIS Section 4.3.3.2.1 discusses Greenhouse gas emissions for the Proposed Action). The effect on climate change related to permafrost effects from the Proposed Action is discussed in the Donlin Gold EIS Section 4.3.3.2.3. The above-ground effects of the No Action alternative would likely be less since it would involve less excavation of permafrost; however, under both alternatives simply maintaining the ROW could adversely affect permafrost stability.

Permanent melting of permafrost results in the release of methane gas and carbon dioxide. There would be some permanent melting under both alternatives, but greater permanent melting would result from the proposed action due to trench

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excavation and hydrology disruption, causing further loss of insulating vegetation and further permanent melting.[5]

6. Cultural Resources

Construction activities have the potential to affect cultural resources. Ground-clearing activities under both cases would be similar. The excavation necessary for a buried pipeline would result in a greater potential for adverse effects to buried cultural resources. The USACE is conducting a Section 106 consultation process with stakeholders; that process will lead to the development of a Programmatic Agreement that would address management and recovery of known cultural resources and any discovered during project implementation. The Programmatic Agreement would apply to both the No Action and Proposed Action alternatives to mitigate effects on these resources. Section 3.20 of the Donlin Gold EIS presents a detailed description of cultural resources and potential impacts (Section 3.20.3.3.3) associated with pipeline construction. There would be no difference between the two alternatives in the event of either a small or large leak for buried segments. A small gas leak from the above-ground segment of the No Action alternative would be unlikely to affect cultural resources.

7. Environmental Justice

Since both pipeline designs would be sited in the same footprint, there would be no difference in effects on environmental justice resulting from construction or operation of the pipeline.

8. Geology, Soils and Mineral Resources

Construction activities have the potential to affect soils in a localized manner with minimal effect on regional geology or mineral resources. Construction activities that could contribute to erosion include clearing and grading, excavation trenching, stockpile management, backfilling, and the development of gravel pads. Most erosion effects are effectively managed through the use of erosion and sediment control measures, including:

- The use of winter construction in areas of wet and frozen ground conditions;

[5] "Road-Related Disturbances in an Arctic Watershed: Analyses of a Spatially Explicit Model of Vegetation and Ecosystem Process." P.W. Leadley, H. Li, B Ostendorf, and J.F. Reynolds. Landscape Function and Disturbance in Arctic Tundra
Volume 120 of the series Ecological Studies pp 387-415. (1996).

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- Minimization of areas of compacted vegetation;
- Salvaging of organic mats used in surface reclamation;
- Use of settlement basins, silt fences, and other Best Management Practices (BMP) for storm water control;
- Use of engineered flow diversions and slope breakers to control water flow on slopes and around water courses; and
- Installation of trench breakers to address storm and groundwater flow through the trench backfill or during construction.

A more detailed discussion of impacts to soils and erosion resulting from the pipeline construction and the potential mitigation measures to address those impacts is provided in Section 3.2.3.2.3 of the EIS. Mitigation measures for erosion and sediment control for both alternatives would be addressed in detail through the Rights-of-Way and Section 404 permitting activities.

The difference in effects to soils would be greater with the buried pipeline since it would result in more physical disturbance to the soil resource. Mineral resources and geology (Donlin Gold EIS Section 3.1.3.2) would be affected in the development of material sites; the need for bedding materials for the buried pipeline would result in a more surface disturbance than an above-ground pipeline.

O&M activities along the pipeline right-of-way to meet 49 CFR Part 192 would be similar for the two alternatives. All O&M excavations would be conducted as authorized under the applicable ROW authorization (ROWs would be issued by one or both of the Bureau of Land Management and Alaska Department of Natural Resources as the land management agencies responsible for lands along the pipeline route). All excavations and other applicable activities would be permitted through the appropriate Federal and State agencies for both alternatives.

No differences in effects between the two cases are expected from a small leak or large rupture since the effects would have come during the construction process and any repairs would be within that foot print.

9. Indian Trust Assets

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No Indian Trust Assets have been identified within the pipeline route.

10. Land Use, Subsistence, and Recreation

During construction, land use in the form of subsistence activities and recreation could be altered in the immediate vicinity of activities. The pipeline's remote location combined with the relatively small width of the ROW would generally limit the extent of displacement by users to the active construction zones. Construction activities would be timed to avoid potential use conflicts with portions of the trail used during the annual Iditarod sled-dog race.

Under both alternatives the route would pass close to, but not overlap, privately held parcels in the Shell Hills Subdivision and the Happy River Remote Recreation Cabin Staking Area. No permafrost along the alignment has been identified in either of these areas and as such there would be no difference between the two alternatives. No existing agricultural areas have been identified within the vicinity of the proposed pipeline route.

The difference in effects from construction of an above- versus a below-ground pipeline would be minor. After construction the ROW would be graded and revegetated to a stable condition. No long term linear access along the pipeline alignment is proposed, however under either alternative PHMSA regulations will require that the pipeline ROW is brushed to prevent the growth of large vegetation over and around the pipeline to maintain a clearly defined ROW. Section 2.3.2.3.6 of the Donlin Gold EIS includes a detailed description of the pipeline ROW footprint and post construction remediation of the ROW. The presence of an above-ground pipeline could create an additional physical barrier in the landscape that would not occur with a buried pipeline. The barrier would represent an adverse effect for both recreational and subsistence land use activities in the vicinity of the pipeline compared to the effects from a buried pipeline. Under either alternative, the differences in effects of either a small leak or large rupture would be negligible for subsistence and recreational use.

Potential effects to recreational, visual, and subsistence uses are examined in detail in Section 3.16, Recreation, Section 3.17, Visual Resources, and Section 3.21, Subsistence of the Donlin Gold EIS.

11. Noise

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Noise impacts during construction would be similar for installation of an above- or below-ground pipeline since much of the equipment would be the same. Impacts would generally be limited to the sounds of construction equipment operations; human use of the area is transient and limited resulting in a relatively short duration of effect (transiting the area). Wildlife could also be affected by construction-related noise. Noise related to operation of the pipeline itself would primarily result from the occasional maintenance of the ROW and limited to the duration of the physical activity. Considering it would be years between these activities, the effect would be minimal and no difference in noise levels is expected between the No Action and Proposed Action alternatives. A detailed discussion of noise impacts associated with pipeline construction and operation is provided in Section 3.9.4.3 of the Donlin Gold EIS.

12. Water Resources

The trenching required for the buried pipe under the Proposed Action could result in additional impacts to surface and groundwater if appropriate design and construction techniques are not utilized for the trenching and backfill of the trench. Appropriate techniques, including the use of trench plugs as discussed in Section 3.6.2.2.3 of the Donlin Gold EIS, will be utilized to prevent the extended flow of groundwater along the trench. The placement of adequate backfill and proper reclamation of the ROW will prevent channeling and obstruction of surface water flows. Stabilization techniques, including gravel blankets, riprap, gabions, or geosynthetics, would be used to stabilize the channel bed and stream banks at stream crossings. The majority of rivers and streams along the pipeline route would be crossed by an open-cut method during winter months when flows are lowest and disturbance of the channel and stream bank can be minimized. Burial depths for crossings have been based on site specific calculations to avoid the potential for scour.

The difference in the effects of a small leak on water resources from an above-ground pipeline and a buried pipeline would be minimal as the gas would pass through any water exposed to a leak underground. A large rupture in an above-ground pipeline would have no effect on water resources; a large rupture in a buried pipeline could introduce natural gas into surface or groundwater although the effect would be both short-lived and localized.

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A detailed discussion regarding the management of water during construction and operation of the pipeline and impacts to ground and surface water flow and quality resulting from the construction and operation of the pipeline is presented in Sections 3.5.3.2.3, 3.6.2.2.3, and 3.7.3.2 of the Donlin Gold EIS.

c. *Describe safety protections provided by the special permit conditions.*

i. What factors were considered to ensure the conditions are adequate to protect against waiving protections (maximum pipe strength limitations) of the code.

The Special Permit will require extensive evaluation of the potential for thaw settlement and other geohazards over the full operational life of the pipeline. Once the potential for settlement has been quantified, an appropriate pipe thickness must be selected to withstand the longitudinal strain that may result. Specific test work requirements for the selection and production of the pipe will be established to ensure that the steel is of appropriate quality. Specific training, monitoring and testing requirements will be established for welding during construction. Specific requirements for monitoring through operations will be established to ensure that any longitudinal strains that exceed those contemplated in the design are identified and mitigated in a timely manner. These are discussed in more detail in Section VII.

ii. What are the safety and environmental risks from usage of strain based design that need to be protected against?

The safety and environmental risks associated with the Proposed Action would result from change to permafrost and wetland conditions, a failure of the pipeline, leading to a leak or rupture and the subsequent release of gas and possible explosion or fire. The use of SBD as outlined in the Special Permit will ensure that the pipeline is designed, constructed, maintained, and operated in a way that avoids failure.

d. *Explain the basis for the particular set of alternative mitigation measures used in the special permit conditions. Explain whether the measures will ensure that a level of safety and environmental protection equivalent to compliance with existing regulations is maintained.*

The basis for the mitigation measures is the expectation that some segments of the pipeline may experience thaw settlement after construction, resulting in unacceptable longitudinal strain on the pipe. To address this expectation, the mitigation measures require the quantification of the maximum amount of thaw settlement possible, the

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selection of an appropriate pipe wall thickness, use of steel of an appropriate quality, and ongoing O&M procedures to deal with increases of the pipeline longitudinal strain. Additional requirements for inspection of the pipeline welds during construction are imposed to ensure weld strength is sufficient to deal with the longitudinal strain. Monitoring requirements during operation are established to ensure that the longitudinal strain does not exceed that contemplated in design, while mitigation requirements are established in the event that does happen.

The use of the above measures ensures that no significant environmental impacts will result from the use of SBD.

e. *Discuss how the special permit would affect the risk or consequences of a pipeline leak, rupture or failure (positive, negative, or none). This would include how the special permits preventative and mitigation measures (conditions) would affect the consequences and socioeconomic impacts of a pipeline leak, rupture or failure.*

The Special Permit will allow for burial of the pipeline in areas that may be susceptible to high magnitudes of thaw settlement, which could lead to increased longitudinal strain on the pipeline and ultimately failure if appropriate mitigation is not in place. The conditions imposed by the Special Permit result in a pipeline that is designed, constructed, and operated in such a way that thaw settlement will not lead to pipeline failure. Under either the Proposed Action or the No Action alternative, the consequences of a pipeline failure would be similar.

f. *Discuss any effects on pipeline longevity and reliability such as life-cycle and periodic maintenance including integrity management. Discuss any technical innovations as well.*

Full implementation of the conditions in the Special Permit will ensure that there are no overall impacts on pipeline longevity and reliability. Implementation of the conditions will impose additional requirements for pipeline integrity management, monitoring, and periodic maintenance.

Requirements for design include:

- The development of an overall SBD Plan that addresses all aspects of the pipeline's life cycle including design, materials, construction, and operations and maintenance (O&M);
- Material testing;
- The development and implementation of written material, design, construction, and O&M specifications and procedures; and

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- Engineering critical assessments.

Requirements for construction include:

- Expanded welding procedure qualification requirements;
- Expanded testing requirements for welds;
- Running a high resolution deformation tool through all SBD segments;
- Expanded grounding and cathodic protection requirements; and
- Development of a ROW monitoring program.

Requirements for O&M include:

- Development of O&M procedures for all operating parameters that have an effect on compliance with the Special Permit;
- Monitoring and determination of pipeline strain demand and specified timelines for remediation;
- Remedial action for coating disbondment;
- Interference current control;
- Integration and analysis of integrity data; and
- Expanded requirements for the reporting and certification including both technical and management oversight.

g. *Discuss how the special permit would impact human safety.*

The Special Permit should improve human safety by allowing for burial of the pipeline in permafrost areas without pipeline failure resulting from thaw settlement. Burial of the pipeline reduces the potential for pipeline failure resulting from human actions or other natural causes, thereby reducing the overall likelihood of failure and the potential for injury from the resulting release of gas. A buried pipeline would also avoid the physical barrier or hazard to recreational and subsistence users of the area that an above-ground pipeline could create.

h. *Discuss whether the special permit would affect land use planning.*

By allowing for burial of the pipeline the Special Permit should provide for increased flexibility in land use planning. Burial will reduce visual impacts associated with the line and reduce the potential for human caused damage to the pipeline. Reduction of these potential impacts reduces the need to consider them in evaluating future land use.

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i. *Discuss any pipeline facility, public infrastructure, safety impacts and/or environmental impacts associated with implementing the special permit. In particular, discuss how any environmentally sensitive areas could be impacted.*

Implementation of the Special Permit will not affect any pipeline facilities, public infrastructure, or environmentally sensitive areas.

V. Consultation and Coordination

a. *Please list the name, title and company of any person involved in the preparation of this document.*

Preparers: Donlin Gold LLC – James Fueg (Technical Services Manager), Gene Weglinski (Senior Permitting Coordinator); Michael Baker International – Paul Carson (Chief Pipeline Engineer) and Keith Meyer

b. *Please provide names and contact information for any person or entity you know will be impacted by the special permit. PHMSA may perform appropriate public scoping. The applicant's assistance in identifying these parties will speed the process considerably.*

Adjacent landowners/land managers potentially impacted:

Cook Inlet Region, Inc.
Jason Brune
Sr. Director, Land and Resources
PO Box 93330
Anchorage
AK 99509
(907) 263-5104

Bureau of Land Management
Alyssa Sweet
Project Manager
BLM Anchorage Field Office
4700 BLM Road
Anchorage
AK 99507
(907) 267-1289

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Alaska Department of Natural Resources
Jason Walsh
State Pipeline Coordinator
3651 Penland Parkway
Anchorage
AK 99508
(907) 269-6419

c. *If you have engaged in any stakeholder or public communication regarding this request, please include information regarding this contact.*

PHMSA has participated in scoping and public outreach lead by the U.S. Army Corps of Engineers related to the Donlin Gold Project Draft Environmental Impact Statement (EIS). Details of the public outreach, which included both members of tribal entities and the general public, are provided in Sections 1.7 and 6.3 of the EIS.

VI. Bibliography

Applicant to document information submitted, if they consulted a book, website, or other document to answer the question, please provide a citation.

VII. Conditions: Example of what special permit (SP) conditions address

a. *If Applicant plans to use strain based design, detail the use of strain based design and the procedures/conditions to be included in a special permit application to address frost heave, thaw settlement, and other geotechnical issues associated with the arctic or sub-arctic.*

Donlin Gold proposes to use SBD to specifically address thaw settlement and any potential for frost heave as discussed in Section II and applied to PHMSA for a Special Permit as described in Section III(b)(i). To accommodate Donlin Gold's request, PHMSA identified the series of Special Permit conditions described below.

b. *The special permit submittal should explain how Applicant will develop and monitor strain based design from a quality assurance standpoint as follows:*

1. **Materials** – specifications for steel strength, pipe bevel misalignment, pipe toughness, steel strength, qualification and manufacturing tests, and steel and pipe mill quality inspections;

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a. *What Regulatory Code and industry standards will be used for steel and pipe qualifications?*

The Donlin Gold pipeline will be constructed of line pipe meeting the requirements of API 5L, Grade X-52, PSL2, and will comply with the additional design requirements for steel pipe using alternative maximum allowable operating pressure as given in 49 CFR § 192.112. In addition, Donlin Gold will develop a pipe material specification to ensure consistent material properties are used for material testing, strain capacity modeling, welding procedures, and strain demand limits. A draft Material Specification for use in SBD segments is contained as Attachment A to the Special Permit.

b. *Will Applicant conduct a small scale and full scale testing program for steel, pipe, girth welds and anomalies (such as corrosion anomalies) to determine tensile strain capacity or limits?*

Donlin Gold will conduct tests and analysis to address the full range of material characteristics, including: chemical compositions, microstructures and manufacturing variables, manufacturers, and girth welding procedures. In addition, the tests will address potential girth weld flaws (type, size, and location) and expected types of anomalies (e.g., corrosion defects, mechanical damage, etc.). The tests and analysis will include, as appropriate, finite element analysis, small-scale testing, medium-scale testing, and full-scale testing. The testing will be conducted on pipe material procured using the Material Specification (Attachment A). As required based on the test results, the Material Specifications may be adapted to reflect requirements for change.

c. *What design safety factor will be used for test program results?*

i. The safety factor for the tensile strain demand limit is 1.667. The tensile strain demand limit is the tensile strain capacity calculated using the procedures, predictive equations and models as outlined in the Special Permit conditions divided by 1.667.

ii. The safety factor for the compressive strain demand limit is defined as follows: The compressive strain demand limit must be the compressive strain capacity calculated using the procedures, predictive equations and models as outlined in the Special Permit conditions divided by 1.25 in Class 1, 2, 3, and 4 locations. In Class 1 locations where the pipeline is not in the right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway and contains less than two buildings within a potential impact circle, as defined in §

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192.903, that have human occupancy of less than 50-days in a 12-month period, a 1.11 factor may be used in-lieu of 1.25.

The test program results will be used to verify the strain capacity values calculated through use of tensile and compressive predictive equations developed by research and analytic reports produced for PHMSA and specified in the Conditions.

d. *What will be the test sample size?*

The test sample sizes for small-, medium-, and full-scale testing are not yet established. The small scale test matrix is developed to supply all of the input aspects required for full scale prediction from the tensile and compressive strain capacity predictive models such as actual yield and tensile/compressive strengths and stress-strain curves to failure. Additional small scale tests, such as fracture toughness, are run to ensure additional minimum requirements for items related to overall pipe safety, but not directly relevant to tensile/compressive strain capacity. The medium scale tests may be performed on short arcs of pipe to simulate the response of an unpressurized pipe to loadings when anomalies are present. All scale tests are in a sense prelude to the full scale tests, and help form the testing matrix for the full scale test program to ensure that all critical aspects of the pipe material, representing critical items that could be present during operations, are addressed.

e. *What tests will be conducted during manufacturing and construction?*

The tests required during pipe manufacturing are presented in Appendix A, Table A-3 of the Special Permit (reproduced below). Tensile tests, hardness tests, and fracture toughness tests will be conducted during weld procedure qualification.

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Special Permit Appendix A Table A-3 Test and Requirements			
Items		Frequency Note 4	Number, location and orientation of specimen
Pipe Body NOTE 1, 3	Chemical composition product analysis	1/heat	1
	Pipe body transverse tensile	1/lot NOTE 2	1 (180°, transverse)
	Pipe body longitudinal tensile (as received)	2/lot	2 (90°, longitudinal)
	Pipe body longitudinal tensile (as aged)	2/lot	2 (90°, longitudinal)
	Charpy impact - pipe body transverse	1/lot	3 (180°, transverse)
	Drop weight tear test (DWTT)	1/lot	2 (180°, transverse)
	Micrograph	1/lot	1 (180°, transverse)
Weld	Welded joint tensile	1/lot	1 (weld, transverse)
	Guided root bending	1/lot	1 (weld, transverse)
	Guided face bending	1/lot	1 (weld, transverse)
	Charpy impact - weld	1/lot	3 (weld, transverse)
	Charpy impact – heat affected zone (HAZ)	1/lot	3 (HAZ, transverse)
	Micrograph	1/lot	1 (weld, transverse)
	Vickers hardness	1/lot	
Hydrostatic pressure test		Each pipe	
Hydrostatic burst test		1 per pipe size	
Visual		Each pipe	
Dimension		Each pipe	
NDT		Each pipe	
Start-up test and start-up certificate test		See Appendix A, Sections 6 and 7 below	

NOTE 1: For helical seam pipe the samples must be taken mid-way between the weld seam.
NOTE 2: A lot is defined as 100 pipes, or per heat, or as per API 5L, whichever is less.
NOTE 3: Yield Strength (YS)/ultimate tensile strength (UTS) less than or equal to 0.90. Uniform elongation greater than 6%.
NOTE 4: Testing frequency and test type must meet both Table A-3 and API 5L criteria.

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f. *How often will tests during manufacturing be conducted – per heat?*

   i. Testing frequencies for each test are outlined in Appendix A, Table A-3 of the Special Permit (see table above).

   ii. In addition, production start-up tests will be conducted as follows:

      Two pipes per heat will be tested for:

      1. Chemical analysis;
      2. Longitudinal and hoop tensile tests (provide full stress-strain curves);
      3. Charpy impact test (pipe body transverse, weld and HAZ), at the specified temperature;
      4. DWTT, at the specified temperature;
      5. Vickers Hardness traverse;
      6. Guided bend test; and
      7. Metallography of pipe body;

   One (1) pipe from each heat will be tested hydrostatically at the pressure producing a hoop stress of 100% of Specified Minimum Yield Strength (SMYS).

2. **Material Test Program –** *What types of small scale and full scale testing, design and material specifications qualifications are needed for the project including girth welds and anomaly effects?*

   Small-scale tests will consist of longitudinal and hoop tensile tests.

   Medium-scale tests will consist of curved wide-plate tests including a range of high-low misalignment, weld flaws, and other anomalies. A curved wide-plate test consists of two sections removed from the pipe, welded together (the final shape resembling a “dog” bone), and then pulled to failure in tension.

   Full-scale tests will consist of pressurized bend tests and will include a range of hi-lo misalignment, weld flaws, and other anomalies.

   Project specific line pipe material and girth weld specifications will be developed and qualified by use of pipe material procured as per the SBD Material Specifications.

a. *How will the remaining wall strength calculations be validated?*

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Operating and Maintenance procedures for remaining wall strength calculations will be developed based on results of the material testing program, finite element analysis of the anomaly, and available PHMSA research on the effects of anomaly wall loss under combined pipeline loadings. Should PHMSA research indicate additional tests are required for the effects of anomalies, Donlin Gold will provide the required tests, finite element analysis, and O&M procedures for the 14-inch pipeline special permit segments.

b. *How will steel and girth weld strength variability be accounted for in the design?*

   i. Design calculations will be performed for a range of steel and girth weld strengths using the results of the project material testing program.

   ii. Donlin Gold intends to utilize critical assessment procedures, predictive equations, and models for calculating tensile and compressive strain capacity in the SBD segments during their life cycle based upon PHMSA research guidance documentation[6]. The procedures address materials (pipes and girth welds) that must operate on the upper shelf (i.e., having ductile behavior) of the brittle-ductile transition. The effects of pipe wall loss or corrosion is currently being addressed by ongoing research sponsored by PHMSA and Donlin Gold will utilize those results as they become available.

3. Geotechnical Test Program

A geotechnical test program has been conducted to characterize the subsurface route conditions. The results of the program have been used to quantify the magnitude and extents of the thaw settlement geohazard and to estimate the strain demand associated with thaw settlement.

a. *Where and how many geotechnical tests will be conducted?*

Nearly 600 geotechnical investigation locations comprising approximately 2,900 laboratory tests have been conducted.

b. *What are engineering parameters for tests?*

The main engineering parameters related to the tests include Unified Soil Classification, moisture content, and thermal state.

c. *What are examples of how pipe will be designed: above ground, heavier wall thickness, or maximum strain?*

[6] **Realistic Strain Capacity Models for Pipeline Construction and Maintenance**, Contract No. DTPH56-10-T-000016, Final Report Prepared for US Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, Prepared by Ming Liu, Yong-Yi Wang, Fan Zhang, and Kunal Kotian; Center for Reliable Energy Systems 5960 Venture Dr., Suite B , Dublin, OH 43017, December 9, 2013

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As described in Section III above – Alternatives, the No Action Alternative will mainly be an above ground installation mode with some sections being constructed using either buried heavier wall thickness pipe, removal and replacement of thaw unstable materials, trenchless technologies, or a combination of these methods. The Proposed Alternative will be designed using strain based design techniques allowing the pipe to experience strains beyond 0.5%, but with strains limited to specified percentages of the material strain capacity established based on actual material testing. The target values of the material strain capacities are based on the engineering assessment of the magnitude of pipe displacements due to ditch settlement along the alignment, using the soil index values from the samples recovered from the field geotechnical investigations.

4. **Design and Construction –** design procedures, specifications, design factors, and inspection including pipe and weld misalignment.

    a. *What are the temperature effects on strain based design loads and tensile strain capacity?*

        i. The temperature differential that the pipeline material experiences, due to the difference between the temperatures of the subsurface at construction tie-in to the operating temperature of the product, causes a mechanical stress (strain) that all pipelines routinely account for in design calculations. Donlin Gold pipeline is considered an ambient line, i.e., the operating temperature is at or near the ambient temperature of the surrounding soils, thus the temperature differential experienced by the line is small and does not have a significant effect on the strain demand.

        ii. The temperature effect of the climate on the subsurface below the pipe after construction may cause thaw of a frozen *in situ* subsurface, due to the change of the surface heat transfer properties. Consolidation of the thawed soils may in turn cause an overall decrease in soil volume and settlement of the pipe ditch bottom. The magnitude of the thaw depth beneath the pipe, along with the associated settlement of the soil within this thaw depth, depends on the geomechanical and geothermal properties of the subsurface, which in turn depends on the properties of the subsurface found from the geotechnical field investigations as discussed in Response #3 above. Section 3.2.3.2.2 of the Donlin Gold EIS discusses thaw settlement and notes that the designs and measures, best management practices, and erosion and sediment control measures are expected to reduce permafrost impacts during construction and operation.

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iii. Temperature does not affect the tensile strain capacity based on the predictive equations developed for PHMSA and specified in the Conditions.

b. *What is the effect of longitudinal loads on MAOP (72% SMYS) operational hoop pressures – do strain based longitudinal loads add to hoop stress, if so how much?*

The hoop stress evaluated as per Barlow's equation, which is the basis for the design formula for pressure containment (49 CFR § 192.105), is unaffected by longitudinal behavior. Barlow's equation is derived from first principles of equilibrium, and does not rely on principles of compatibility for its derivation. A consequence of the derivation is that actions in the longitudinal direction do not affect the hoop stress evaluation. Based upon a 14-inch diameter, 0.276-inch, API 5L Grade X-52, pipeline the MAOP is 1480 psig.

c. *What is the effect of steel strength, weld property, and wall loss due to corrosion on the strain capacity of pipe under longitudinal and hoop stresses?*

i. Donlin Gold intends to utilize critical assessment procedures, predictive equations, and models for calculating tensile and compressive strain capacity in the SBD segments during their life cycle based upon PHMSA research guidance documentation[7].

ii. Generally, the approach used by Donlin Gold for the evaluation of wall loss due to corrosion is that the effect of longitudinal strain must be technically considered in the presence of metal wall loss or other anomalies. Metal loss must be maintained below 20% of the pipe wall thickness (see Special Permit Condition 18) and pressure failure ratios maintained in accordance with Condition 23, when the longitudinal strain magnitude exceeds 0.5%. Anomalies greater than 20% wall loss up to 40% wall loss may be allowed in SBD segments with longitudinal strains over 0.5% strain but must be evaluated with Operations & Maintenance (O&M) Procedures based upon a destructive test program, finite element analysis, or a combination of the two methods. The effects of pipe wall loss or corrosion is currently being addressed by ongoing research sponsored by PHMSA and Donlin Gold will utilize those results as they become available. The results of the

[7] **Realistic Strain Capacity Models for Pipeline Construction and Maintenance**, Contract No. DTPH56-10-T-000016, Final Report Prepared for US Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, Prepared by Ming Liu, Yong-Yi Wang, Fan Zhang, and Kunal Kotian; Center for Reliable Energy Systems 5960 Venture Dr., Suite B , Dublin, OH 43017, December 9, 2013

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PHMSA research could require Donlin Gold to conduct further tests on the effect of pipe wall loss or corrosion on longitudinal strains.

d. *What will be the safety factor used for longitudinal stresses – will these stresses be over 100% SMYS, if so what safety factor will be used and what are the expected strain design factors?*

The intent of the SBD approach is to accommodate longitudinal stresses in excess of 100% SMYS. The safety factors to be applied are discussed in Section VII(b)(1)(c) above.

e. *What construction inspection procedures and processes will be in-place to ensure geotechnical limits for strain based design are not exceeded during construction?*

Longitudinal stress and strain during construction will be calculated based upon the anticipated pipe ditch installation procedure. Donlin Gold will specify pipe lifting and lowering-in practices, ditch depths, lift heights, number of lift points, and spacing between lift points as part of the construction quality assurance procedures. The intent of the construction specifications is to ensure that the pipe stress during pipeline installation remains below 100% SMYS and as further defined in 49 CFR Part 192 and the Special Permit conditions.

f. *How many and what types of geotechnical tests need to be conducted along the right-of-way in areas where strain based design will be implemented?*

Geotechnical testing has been conducted throughout the length of the SBD segment. See Section VII b (3)(a) above.

g. *How will the pipeline be cathodically protected during construction to ensure anomalies do not jeopardize strain based design and integrity management?*

The Special Permit does not require that the pipeline be cathodically protected during construction, only that cathodic protection is provided within one year of backfilling. Prior to installation, the pipe is only subject to atmospheric corrosion mechanisms, which are significantly less pronounced than those experienced in a buried environment. Atmospheric corrosion will be negligible during the time between pipe production and construction due to the application of a high-quality corrosion coating (fusion-bonded epoxy) to the exposed exterior surface. A sacrificial anode system will be installed along the entire length of the SBD segments.

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h. *How will the pipeline be checked before and/or after construction to ensure low strength pipe has not been installed?*

A high resolution deformation in-line inspection tool will be run along the length of the SBD segment no later than the end of Pipeline Start-Up.

i. *Will all girth welds be non-destructively tested to ensure strain based design is applicable? Due to the pipeline high operating pressures, will all girth welds be non-destructively tested?*

All girth welds along the length of the SBD segment will be non-destructively tested in accordance with 49 CFR Part 192 and the Part 192 referenced edition of API Standard 1104 – "Welding of Pipelines and Related Facilities".

j. *Due to the high operating pressures of the pipeline, will the pipeline have Charpy impact values that arrest a running fracture, if so, how will the pipe toughness be designed to limit this operating failure effect?*

The pipeline will be constructed of materials operating on the upper shelf of the brittle-ductile transition as demonstrated by results of Charpy impact tests with sufficient energy values to self-arrest a running fracture. The higher Charpy impact values are needed to either stop or arrest a pipe from rupturing, if it should failed from an anomaly in the pipe wall.

k. *What will be the minimum pressure test factors used: for Class 1, 2 and 3 locations, compressor stations, and major river crossings?*

All pressure tests will be conducted in accordance with 49 CFR Part 192, Subpart J.

The pipeline is characterized as Class 1 for the entire length and the minimum pressure test factor will be 1.25 times the MAOP in all mainline locations. Compressor stations, regulator stations, and meter stations would be pressure tested to 1.5 times MAOP in accordance with 49 CFR § 192.505(b).

5. **Operations and Maintenance (O&M) –** monitoring for frost heave, thaw settlement, and other atypical earth movement issues associated with the arctic or sub-arctic;

a. *The methodology for determining stress and strain.*

Donlin Gold will develop and implement a strain demand monitoring system that will focus on use of an inline inspection (ILI) tool to evaluate changes in curvature of the pipeline. The curvature change, from which pipe strain can be

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directly calculated, is a direct assessment of the longitudinal bending that the pipe is undergoing due to a change in the pipe ditch profile. By comparing the results from successive ILI runs, the strain growth rate can be calculated to calibrate the required frequency of future ILI runs. If a pipe segment experiences strains in excess of 0.5%, additional on-location monitoring procedures and methods are used to verify the reliability and accuracy of the O&M procedures, as well as to provide additional information on strain growth in the time intervals between ILI runs. Additional details on the reporting and remediation requirements are specified in Table 1 of Condition 17 of the Special Permit reproduced below.

b. *What will be the timing of inspections and remediation procedures, if not developed, when will procedures be developed?*

   i. Inspections will be conducted utilizing a geospatial pipeline mapping in-line inspection tool. Per the SBD Conditions, the tool must be run not later than the end of Pipeline Start-Up and once each calendar year not to exceed fifteen (15) months thereafter. Alternatively, after the first three (3) tool runs, the timing of future tool runs may be determined by comparing the rate of increase in site-specific strain demand with the remaining margin between site-specific strain demand and site-specific strain demand limit.
   ii. The SBD Conditions require remediation once a strain demand condition of greater than or equal to 75% of the strain demand limit is discovered. This equates to a safety factor of 2.22 (the specified safety factor of 1.667 divided by the 75% limit when remediation is required) on tensile strain capacity and 1.47 (1.10/0.75) to 1.67 (1.25/0.75) on compressive strain capacity. See Section VII (b)(1)(c) for more information on safety factors.
   iii. Remediation procedures will be developed during final design and before Pipeline Start-up.

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Special Permit Table 1: Pipeline Segment Onsite Strain Demand Monitoring				
Strain Demand Magnitude that Triggers Action		**Action Required**	**Minimum Density of Monitoring Locations**	**Frequency of Data Collection**
Level	**Strain Demand**			
1	Greater than 0.5% longitudinal strain and less than 75% of strain demand limit	Monitor	One per every 10 joints of pipe	Once every six (6) months, or earlier based upon growth rate calculations
2	Equal to or greater than 75% of strain demand limit and less than 90% of strain demand limit	Monitor. Develop site specific strain growth rate and corresponding remediation plan to ensure strain demand limit is not reached during Operational Life. The remediation plan must be implemented within one (1) year of the date of discovery, or prior to the date when the strain demand limit is expected to be exceeded, whichever is sooner.	One per every 2 joints of pipe	Once every three (3) months, or earlier based upon growth rate calculations
3	Equal to or greater than 90% of strain demand limit	Report to PHMSA Regional Director within 5 days of discovery. Develop remediation plan with PHMSA within 30 days of discovery. The remediation plan is to be implemented within 1 year of the date of discovery, or 90 days prior to the date when the strain demand limit is expected to be exceeded, whichever is sooner.	One per every 1 joints of pipe	Once every one (1) month or earlier based upon growth rate calculations, until remediation is complete.

c. *Has a temperature study been conducted on maximum operational temperatures and permafrost effects, if so findings? What criteria will be used to determine whether or how long it is safe to operate the pipeline if chillers are inoperable?*

The pipeline will operate near seasonal ambient ground temperatures; Donlin Gold is not proposing the use of chillers. The maximum gas pipeline discharge temperatures from the compressor station are 40°F and 100°F in the winter and summer, respectively as the gas will be processed through an air-cooled heat exchanger (fin-fan) to reduce the gas temperature to within 20 degrees of ambient, but not less than 40°F. The intent

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of the SBD approach to pipeline design is to account for potential thaw settlement and any frost heave in permafrost areas.

d. *How will maximum temperature compressor station temperatures be maintained to ensure permafrost melt will not affect pipe buoyancy and add additional stresses to the pipe?*

The intent of the SBD approach to pipeline design is to account for potential thaw settlement and any frost heave in permafrost areas. The Donlin Gold pipeline will operate near seasonal ambient ground temperatures. The single compressor station (only one station is required) is located a sufficient distance from areas of permafrost to have no effect on thawing. The gas will be processed through an air-cooled heat exchanger (fin-fan) to reduce the gas temperature to within 20 degrees of ambient, but not less than 40°F. The gas temperature is predicted to equilibrate with the ground within the first 50 miles and no permafrost has been identified within this section of the line.

e. *How will the pipeline be chilled between installation and first gas to prevent permafrost degradation?*

The pipeline will not be chilled. The intent of the SBD approach to pipeline design is to account for potential thaw settlement and any frost heave in permafrost areas.

6. **Integrity Management** – assessment timing for baseline assessments and re-assessments taking into account usage of strain based design and MAOP.

a. *How will the engineering evaluations for anomaly assessment be validated and applied during integrity assessments for tensile strain based design?*

Operating and Maintenance procedures will be developed based on results of the material testing program and available PHMSA research on the effects of anomaly wall loss under combined pipeline loadings to evaluate anomalies during engineering evaluations. The procedure will be supplied to PHMSA in an Operations and Maintenance Plan for review six months before the start of pipeline Operations as outlined in the SBD special permit.

b. *What design factors will be used for maximum longitudinal strain loads, before remediation?*

The SBD Conditions require remediation once a strain demand condition of greater than or equal to 75% of the strain demand limit is discovered. This

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equates to a safety factor of 2.22 (the specified safety factor of 1.667 divided by the 75% limit when remediation is required) on tensile strain capacity and 1.47 (1.10/0.75) to 1.67 (1.25/0.75) on compressive strain capacity. See Section VII (b)(1)(c) for more information on safety factors.

c. *What are integrity assessment timing intervals for tensile strain based design assessments?*

Integrity assessments associated with strain based design will be conducted utilizing a geospatial pipeline mapping in-line inspection tool. Per the SBD Conditions, the tool must be run not later than the end of Pipeline Start-Up and once each calendar year not to exceed fifteen (15) months thereafter. Alternatively, after the first three (3) tool runs, the timing of future tool runs may be determined by comparing the rate of increase in site-specific strain demand with the remaining margin between site-specific strain demand and site-specific strain demand limit.

Strain Based Design Special Permit

CONDITIONS – Draft - 08/11/2015

Donlin Gold Limited Liability Corporation

The following strain based design ***(SBD) Conditions*** take into account the material, design, construction, and operational and maintenance (O&M) parameters, which a pipeline operated using SBD**,** must incorporate during its operating life cycle. The ***SBD Conditions*** are organized into sections as follows: Overview, Design and Materials, Construction, Operations and Maintenance (O&M), Reporting and Certification, Nomenclature, Limitations, and Appendix A – Pipe.

Overview:

1) **Maximum Allowable Operating Pressure (MAOP):** The Donlin Gold Limited Liability Corporation (DGLLC) must operate the ***SBD Segments***[1] at or below a maximum allowable operating pressure (MAOP) of 1480 pounds per square inch gauge (psig) for the 14-inch natural gas pipeline. The DGLLC pipeline must be designed to be operated at a hoop stress of 72% specified minimum yield strength (SMYS) or less.

2) **Applicable Regulations:** These ***SBD Conditions*** are applicable to the ***SBD Segments*** of the DGLLC pipeline. In addition to the provisions of 49 CFR Part 192 that apply to the ***SBD Segments***, and although the DGLLC will not be operated at a hoop stress in excess of 72% SMYS, all ***SBD Segments*** of the DGLLC pipeline must be designed, constructed, operated and maintained in accordance with 49 CFR §§ 192.112, 192.328, 192.620, and these ***SBD Conditions*.** In the event of a conflict between these ***SBD Conditions*** and the applicable requirements under 49 CFR Part 192, the ***SBD Conditions*** must control.

3) **Strain Based Design Plan (*SBD Plan*):** DGLLC must develop and submit to the Pipeline and Hazardous Materials Administration (PHMSA[2]) for review an overall ***SBD Plan*** that

[1] ***SBD segment(s)*** consist of the pipeline from Mile Post YYY to YYY (TBD).

[2] Throughout these ***SBD Conditions*** where documents must be submitted to PHMSA and no contact is named, DGLLC must submit the project documents to the PHMSA Director, Western Region or PHMSA project designee.

addresses all aspects of the pipeline's life cycle including design, materials, construction, and operations and maintenance (O&M) for use of SBD techniques that meets all the conditions of these ***SBD Conditions*** and 49 CFR Part 192, as stated in Condition 2 above. The ***SBD Plan*** must be developed for the entire pipeline life cycle, from design through operations, for all line pipes, girth welds, and pipeline components subjected to longitudinal strain with a magnitude greater than 0.5%. The influence of adjacent pipes (including field bends) experiencing longitudinal strains greater than a magnitude of 0.5% on the integrity of hot bends, tees, valves and other fittings must be examined and validated. Strain concentrations may occur at the transition regions (such as transition pups) from the thinner wall thickness pipe to pipe with thicker wall thickness. The girth welds in these regions must be qualified and inspected for strength, toughness, flaws, and other properties to ensure their integrity is in accordance with Conditions 7, 8, and 9.

a) The three elements of the final ***SBD Plan*** (Design and Materials, Construction, Operations and Maintenance) must be submitted to PHMSA in accordance with the following schedule:

    i) Design and material specifications and procedures for SBD must conform to Conditions 4 through 7, inclusive, and must be submitted to PHMSA for review six (6) months prior to rolling steel for pipe.

    ii) Construction specifications and procedures for SBD must conform to Conditions 8 through 14, inclusive, and must be submitted to PHMSA for review six (6) months prior to beginning of construction.

    iii) Operations and Maintenance (O&M) specifications and procedures for SBD must conform to Conditions 15 through 23, inclusive, and must be submitted to PHMSA for review six (6) months prior to placing the pipeline into natural gas service.

    iv) After placing the pipeline into natural gas service, DGLLC must meet with PHMSA to review the ***SBD Plan*** for O&M (Conditions 15 through 23) each year for the first two (2) years after initial operation, and every second (2nd) year thereafter[3] or as otherwise required by these ***SBD Conditions*** or requested by PHMSA. DGLLC must review compliance with the ***SBD Plan*** in the annual DGLLC Integrity Management Plan report submitted to PHMSA. This review must include Condition 24 and the below as a minimum:

1. Any segments that exhibit longitudinal strains in excess of a magnitude of 0.5% ("high strains");
2. All ongoing monitoring of pipe segments that exhibit high strains;
3. Planned maintenance of high strain regions; and
4. Analysis of the strain increase in high strain regions, including estimation (based upon geotechnical and operational data) of expected strain for the next annual cycle.

b) Each element of the ***SBD Plan*** set out in Condition 3(a)(i) through (iii) must be reviewed and validated by a third party engineering expert/firm. The third party engineering expert/firm must be retained by DGLLC, in advance of DGLLC's submittal to PHMSA[4] for review. The independent third party engineering expert/firm must be agreed upon between DGLLC and PHMSA. The role of the third party engineering expert/firm is to ensure the ***SBD Plan*** element is consistent with the applicable ***SBD Conditions***.

i) In advance of submittal of the final ***SBD Plan*** elements set out in Condition 3(a)(i) through (iii), DGLLC, PHMSA and DGLLC's third party engineering expert/firm must undertake joint technical review meetings to discuss the draft ***SBD Plan*** elements and relay their respective comments. To the extent practicable, the joint technical review meetings must be scheduled at least 60 days prior to submittal of the final ***SBD Plan*** elements set out in Condition

[3] DGLLC may request a change of these meetings from every second year up to every fourth year, but this meeting date change would require a "no objection" from PHMSA's Director of Western Region or PHMSA Project designee.

[4] In situations where PHMSA determines that referenced conditions or a portion of the referenced conditions do not require a third party engineering expert/firm review and with a written substantiated request by DGLLC, PHMSA may issue a "no objection" to not require a third party engineering expert/firm review.

3(a)(i) through (iii). Prior to the joint technical review meeting, DGLLC must submit the respective draft ***SBD Plan*** element to PHMSA.

ii) Comments must be resolved in joint technical meetings of DGLLC, PHMSA, and DGLLC's third party engineering expert/firm.

iii) This review process can be adjusted with mutual consent of DGLLC and PHMSA.

c) DGLLC and PHMSA agree a set of ***SBD Conditions*** is necessary for the safe design, construction and operation of the DGLLC pipeline. DGLLC may propose changes to these ***SBD Conditions***, review dates or timing to PHMSA for "no objection". Any proposed ***SBD Condition*** changes (Conditions 1 through 26) by DGLLC must maintain equivalent levels of safety. PHMSA will determine the level of ***SBD Condition*** changes that may require a modification or public notice of the special permit. Any ***SBD Condition*** submittal timing, review timing, or completion timing in these ***SBD Conditions*** can be modified by PHMSA upon request by DGLLC and with a "no objection" from PHMSA[5] to DGLLC.

<u>Design and Materials</u>:

4) **<u>Material Specifications</u>:** The DGLLC pipe material specifications for SBD are contained in Appendix A[6]. The DGLLC pipe material specifications must be consistent with the requirements in Conditions 5 and 6 and ensure the pipe is manufactured to achieve a sufficient level of strain capacity as discussed in Conditions 6 and 7 while accommodating variations in yield/tensile (Y/T) ratio, elongation, and tensile strength in hoop and longitudinal directions, pipe chemical composition, microstructures and steel rolling and cooling practices. Any material test reports required by the DGLLC pipe material specifications and submitted to DGLLC must also be made available to PHMSA upon request.

[5] DGLLC must submit any proposed changes to the ***SBD Conditions*** to PHMSA Director, Western Region or PHMSA project designee for review and "no objection" prior to usage.

[6] References to industry standards, such as API 5L, must be to an approved edition listed in § 192.7. In the event there is a conflict between these conditions and a referenced standard, the more stringent conditions must be used. If industry standards are used that are not referenced in 49 CFR Part 192 and not expressly included in these ***SBD Conditions***, DGLLC must obtain a "no objection" from PHMSA for usage of the industry standard and edition.

5) **Material Testing:** DGLLC must implement a process to determine longitudinal-tensile and compressive strain capacity of pipe and girth welds, representing all anticipated operating and environmental conditions the pipeline will be subjected to during its life cycle in conjunction with Conditions 6, 7, and 8. The process must explicitly account for all parameters appropriate to the pipeline's design and operational life cycle, including but not limited to, pipe diameters, wall thicknesses, grades, flaws (type and size), corrosion, and internal and external loading. The cyclic stress from environmental loading (such as frost heave and earthquake ground motions) and operational parameters (pressure, temperature, etc.) must also be considered. The process must include, as appropriate, finite element analysis, small-scale testing, medium-scale testing (e.g. curved wide plate testing), and full-scale testing.

   a) The DGLLC Material Testing program must perform tests to address the pipe material properties of Condition 4 and Appendix A. The variations of pipes and girth welds being tested must represent those of expected production pipe, double jointing welds, field welds, tie-in welds, repair welds, and their variations, as provided in pipe specifications of Condition 4 and Appendix A. The tests must validate the pipes have the necessary properties to achieve the tensile and compressive strain capacity under combined loadings for field installation, operations, and environmental conditions.

   b) DGLLC must conduct tests and analysis to address the full range of material characteristics, including: chemical compositions, microstructures and manufacturing variables, manufacturers, and girth welding procedures. The tests and analysis must include, as appropriate, finite element analysis, small-scale testing, medium-scale testing, and full-scale testing.

   c) The DGLLC Material Testing program must address, at a minimum, the following parameters:

      i) Source and type of pipes (e.g. UOE, JCOE, etc.), steel chemical composition, and rolling practice,

      ii) Range of mechanical properties, including strength, strain hardening rate (e.g., Y/T ratio), and effects of strain aging,

      iii) Girth welding process (mainline welds, double joint welds, tie-in welds, repair welds, and welds to fittings),

- iv) Girth weld mechanical properties (including strength, toughness, and ductility),
- v) Girth weld high-low misalignment,
- vi) Pipe material design conditions (e.g., D/t ratio, design factor),
- vii) Construction conditions,
- viii) Operational pressure,
- ix) Operational temperature,
- x) Girth weld flaw (flaw type, flaw location, i.e., surface-breaking[7], flaw length, flaw depth, flaw height, weld metal versus heat affected zone (HAZ)),
- xi) Expected anomalies (such as corrosion defects, mechanical damage, cracking defects (if allowed), etc.), and any other parameters that significantly influence the strain capacity, and
- xii) When appropriate, the conditions corresponding to the maximum, nominal, and minimum values of those parameters must be technically considered and tested.

d) Full-scale testing must be performed to validate the strain capacity at critical project operational conditions[8]. If full-scale testing of a critical condition is deemed not feasible, the validation of the strain capacity must be conducted through a combination of small-scale testing, medium-scale testing, or numerical analysis by qualified labs and technical analysts. DGLLC must technically justify why the full-scale testing is unfeasible and submit an alternative plan to the full-scale testing to PHMSA for review and "no objection".

e) For tests for which standardized procedures sanctioned by standard-making organizations do not exist, or standardized procedures do not cover key elements

[7] The impact of embedded flaws must be considered, including but not limited to, re-characterizing embedded flaws as surface-breaking flaws.

[8] Prior to submittal of the draft and final ***SBD Plan*** elements, DGLLC may conduct such material testing as it deems necessary for the development of the ***SBD Plan*** elements. Prior to conducting such material testing DGLLC will coordinate and consult with PHMSA on such material testing. Where PHMSA has coordinated and consulted on such material testing, DGLLC may incorporate the material testing and results into the draft and final ***SBD Plan*** elements.

affecting the outcome of the tests[9], DGLLC must develop test procedures[10] for material test laboratories to use throughout the project to obtain consistent results.

i) The following test procedures must be evaluated:

a. Tensile test of pipe hoop and longitudinal properties,

b. Tensile test of all-weld metal,

c. Charpy test of pipe,

d. Charpy test of girth weld heat-affected zone (HAZ) and weld metal, and

e. Crack Tip Opening Displacement (CTOD) test and Single-Edge Notched Bending (SENB) test of girth weld HAZ and weld metal.

ii) The following test procedures must be evaluated, unless DGLLC can technically justify why a test procedure is not feasible:

a. Single-Edge Notched Tensile (SENT) test of girth weld HAZ and weld,

b. Curve Wide Plate (CWP) test of girth weld HAZ and weld, and

c. Full-scale test.

f) Each of the test procedures must include the following parameters, as appropriate for the type of test:

i) Specimen removal from pipe or weld:

a. Specimen orientation (longitudinal or hoop direction),

b. Specimen position (o'clock around the circumference, thickness position)

c. Method of removal, including the possible effects of cutting and machining heat on the materials being tested),

ii) Specimen dimensions, including tolerance,

iii) Specimen machining, including tolerance,

iv) Placement of notch, including process of locating the notch with respect to the target microstructure, notch front acuity,

v) Electrical discharge machining (EDM) notching of flaws,

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9 For instance, tensile test of round bar specimens is covered by a number of standardized test procedures. However, procedures of specimen extraction (e.g., specimen position relative to the pipe wall, specimen dimensions) from pipes and girth welds may not be covered by those test procedures.

10 Material test procedures must include a schedule of periodic (minimum of six (6) months) verification of the key parameters of the testing process as listed in Condition 5(c) to ensure test result quality and repeatability of results.

vi) Instrumentation plan,

vii) Calibration of instruments,

viii) Calibration of test machine,

ix) Test temperature and uniformity of the test temperature throughout tests,

x) Loading procedure, including internal pressure if applicable,

xi) Data collection rate,

xii) Acquisition and storage of raw test data,

xiii) Data processing procedure and possible corrections to machine compliance if applicable,

xiv) Post-processing of raw data,

xv) Data reporting, including raw data, processed data, fracture surfaces, if applicable,

xvi) Verification of test data,

xvii) Validity criteria of flaw dimensions if applicable,

xviii) Validity criteria of test data if applicable, and

xix) Verification of notch location if applicable.

Parts of the test procedures may be referenced from published test standards. Parts of the test procedures not covered by the published test standards must be supplemented by the project test procedures. A document containing all test procedures must be provided to PHMSA prior to commencement of the test.

g) A fracture control plan must be developed to determine the fracture arrest for pipe from each unique combination of steel mill,[11] pipe diameter, wall thickness and grade to meet 49 CFR § 192.112(b). It is recognized most full-scale fracture arrest tests have been done with low longitudinal stresses and strains. Fracture arrest behavior could be affected by the existence of high longitudinal strain, if an event were to occur when the pipeline is under such conditions. DGLLC must justify whether the

[11] A steel mill must use the same rolling parameters through-out the steel making process. If rolling parameters and steel compositions materially change during the manufacturing process, additional destructive tests must be conducted as if the steel was rolled by another manufacturer. DGLLC has the option to submit to PHMSA documentation of why rolling parameters, steel composition, and manufacturer changes would not affect pipe fracture arrest.

fracture arrest plan, if developed under low longitudinal strain conditions, is still applicable through Charpy testing in the strained and aged condition.

h) Destructive tests must be used to determine the ability of all crack arrestor designs used to stop and arrest an operational pipe fracture to meet 49 CFR § 192.112(b) and tests must be conducted using pipe from each unique combination of steel mill, pipe diameter, wall thickness and grade. The influence of high longitudinal strain must be technically considered in fracture arrest for the crack arrestor.

6) **Design Procedures:** Based upon the findings from the DGLLC Material Testing program and analysis as required in Conditions 5, DGLLC must develop and implement written material, design, construction, and O&M specifications and procedures in accordance with these *SBD Conditions* to prevent the strain demand for pipe and girth welds from exceeding the defined strain demand limits under operational conditions for the ***SBD Segments***. Specifications and procedures must be based upon Condition 5 test and analysis results and engineering critical assessment as specified in Condition 7. The specifications and procedures must be refined as construction and operational history becomes more developed.

a) Tensile and compressive strain demand limits must be established as follows:

i) The tensile strain demand limit must be the tensile strain capacity calculated using the procedures, predictive equations and models in accordance with Condition 7[12] divided by 1.667[13].

ii) The compressive strain demand limit must be the compressive strain capacity calculated using the procedures, predictive equations and models in accordance with Condition 7[14] divided by 1.25 in Class 1, 2, 3, and 4

[12] The procedures, predictive equations, and models described in Condition 7 may be reviewed and technically adjusted to incorporate the results of the DGLLC Material Testing Program as described in Condition 5. A document detailing the review and technical adjustment process (including how any new models produce the same or better consistency and accuracy in predicting tensile strain capacity) must be submitted to an independent third party engineering expert/firm for review and to PHMSA for "no objection." If DGLLC adjusts the predictive equations and models described in Condition 7 after obtaining "no objection" from PHMSA, the review and technical adjustment process must be incorporated into the draft and final ***SBD Plan*** elements.

[13] An alternative equivalent method of determining the tensile strain limit would be 0.60 times the tensile strain capacity in Condition 7.

[14] See footnote 12.

locations. In Class 1 locations where the pipeline is not in the right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway and contains less than two buildings within a potential impact circle, as defined in § 192.903, that have human occupancy of less than 50-days in a 12-month period, a 1.11 factor may be used in-lieu of 1.25.

iii) The tensile and compressive strain demand limits must not exceed 2%.

b) The strain demand must be technically based upon, and technically account for:

i) Field conditions – above ground, below ground, seismic, permafrost, soil loads, settlement, or movement along the pipeline;

ii) Different operational pressures – maximum to minimum;

iii) Pipe temperatures, which include contributions from both operational and environmental heat sources/sinks – maximum to minimum; and

iv) Seasonal changes in operational and environmental conditions.

c) The strain capacity must be technically based upon, and technically account for:

i) Variations in pipe tensile properties, pipe diameter, wall thickness, ovality, and out-of-roundness;

ii) Flaws in girth welds that account for welding procedures actually used, high-low misalignment, engineering critical assessment as specified in Condition 7, construction and operational loads, and girth weld flaw sizes; girth weld variability, repair, and welder re-qualification limits; and

iii) Pipe strain aging and hardening effects on the pipe properties, including pipe strength, yield strength to ultimate tensile strength (Y/T) ratios, and pipe elongation from the pipe coating heating effects during external or internal coating applications.

7) <u>Engineering Critical Assessment</u>:

a) Part I - Tensile Strain Capacity[15]

[15] See footnote 12.

Engineering Critical Assessment (ECA) procedures, predictive equations, and models for calculating tensile strain capacity in the ***SBD Segments*** during their life cycle must adequately address the following parameters:

i) The materials (pipes and girth welds) must operate on the upper shelf[16] (i.e., having ductile behavior) of the brittle-ductile transition.

ii) Combined loading effects from longitudinal stress, hoop stress, and environmental loads.

iii) Pipe wall loss or corrosion

iv) Geometric pipe parameters including but not limited to:

   a. Pipe geometry including wall thickness,
   b. Girth weld high-low misalignment, and
   c. Type of joints, including pipe to pipe, pipe to bend, pipe to fitting, and pipe to valve.

v) Pipe material and girth weld property parameters, including but not limited to:

   a. Full stress-strain curve,
   b. Y/T ratio,
   c. Uniform strain,
   d. Total elongation,
   e. Weld strength mismatch at ultimate tensile strength (UTS),
   f. Flaw size (height and length),
   g. Flaw location (weld metal or HAZ),
   h. Flaw geometry (surface breaking, embedded, etc.)
   i. Heat affected zone (HAZ) hardening or softening,
   j. Weld toughness properties for weld centerline and HAZ including Crack Tip Opening Displacement (CTOD), Single Edge Notched Tensile (SENT) Resistance Curves (R-Curves), Charpy Transition Curves, Curved Wide Plate, or other tests with pre-approved qualified test

[16] The brittle-ductile transition behavior must be established by conducting one or more of the following tests: (1) Charpy impact, (2) DWTT, or (3) full-scale. The effects of specimen size and flaw-tip constraint conditions may be considered and accounted for in predicting materials' full-scale behavior. When ductile shear area can be determined, having 85% shear area may be viewed as achieving ductile behavior. If the ductile shear area cannot be determined, **a** full transition curve based on total energy must be used to determine the attainment of the ductile behavior.

procedures, and

k. Flaw interaction rules suitable for strain-based design[17].

vi) The predictive equations or models for tensile strain capacity must evaluate the possible failure modes and locations for tensile strain capacity including, but not limited to, crack initiation, ductile tearing, and plastic collapse in the pipe and weld and the possibility of brittle failure. The predictive equations must be validated by the tests specified in Condition 5.

a. The Level 2 and 3 equations of PHMSA/PRCI project[18] must be used as the predictive equations in the ***SBD Plan***. Alternatively, DGLLC project specific equations or models may be used, provided they meet the following criteria:

i) These equations include the same or more physical parameters as in the PHMSA/PRCI equations.

ii) These equations provide the same or better consistency and accuracy in predicting the tensile strain capacity against the DGLLC project test data and the full-scale test data in the PHMSA/PRCI project report than the PHMSA/PRCI equations.

iii) These equations provide the same or better consistency and accuracy in predicting the tensile strain capacity against other public-domain large-scale test data (curved wide plate and full-scale) as the PHMSA/PRCI equations. The details of the large-scale test data and their accompanying small-scale tests must be available to qualify the data as the basis for comparing the predictive equations.

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[17] Flaw interaction rules must cover all possible scenarios that can occur in the field, including but not limited to, interaction of stacked flaws at weld starts and stops and interaction of surface-breaking and bedded flaws. API 1104, Appendix A, provides examples of various possible scenarios. Flaw interaction rules for strain-based design conditions are not well developed. Methodology in the following references can be used as a guide to develop flaw interaction rules: (1) Wang, Y.-Y., Liu, M., Long, X., Stephens, M., Petersen, R., and Gordon, R., "Validation & Documentation of Tensile Strain Limit Design Models for Pipelines," PRCI Project ABD-1, US DOT Agreement DTPH56-06-T000014, Final report, August 2, 2011, http://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=200 and (2) a paper by Tang et. al. at ISOPE 2014-1-14-556. Flaw interaction rules must be submitted to PHMSA for review and "no objection".

[18] Wang, Y.-Y., Liu, M., and Song, Y., 2011, "Second Generation Models for Strain-Based Design," PRCI Project ABD-1, US DOT Agreement DTPH56-06-T000014, Final report, August 30, 2011, http://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=201.

b. If the DGLLC project-specific predictive equations cannot meet the conditions of 7(a)(vi) above, no tensile strain capacity greater than those from the PHMSA/PRCI predictive equations can be used in the design, construction, and O&M.

c. The use of the company- or project-specific prediction equations must be addressed in the ***SBD Plan***, which is reviewed by an independent third party engineering expert/firm and PHMSA as per Condition 3(b).

b) Part II – Compressive Strain Capacity[19]

The predictive equations and models for calculating compressive strain capacity in the ***SBD Segments*** during their life cycle must adequately address the following parameters:

i) Pipe diameter,
ii) Pipe wall thickness,
iii) Pipe imperfections,
iv) Field cold bending and its impact on material properties,
v) Material grade,
vi) Material strain hardening rate (Y/T ratio),
vii) Internal pressure,
viii) Operational temperature,
ix) All weld metal strength of girth weld,
x) Girth weld misalignment, and
xi) Type of girth welds, including transition joints between different wall thicknesses.

c) Part III – Interaction of Pipe Anomaly and Longitudinal Strain

i) In addition to technically considering the strain capacity which is measured in the pipe longitudinal direction in Part I and Part II above (Condition 7(a) and (b)), the hoop strain limit must be maintained to a safe level when the interaction of hoop strain and longitudinal strain is technically considered in

[19] See footnote 12.

the presence of metal wall loss or other anomalies. The interaction of hoop strain and seam weld must be technically considered.

ii) Unless justified by research[20] or as provided below, metal loss must be maintained below 20% of the pipe wall thickness (see Condition 18) and pressure failure ratios (PFR) maintained in accordance with Condition 23, when the longitudinal strain magnitude exceeds 0.5%.

iii) Anomalies greater than 20% wall loss up to 40% wall loss may be allowed in ***SBD Segments*** with longitudinal strains over 0.5% strain but must be evaluated with O&M Procedures that are based upon a destructive test program**,** finite element analysis, or a combination of the two methods, which validates the procedures. DGLLC must develop O&M Procedures based upon the results of the DGLLC Material Testing program as described under Condition 5 and available PHMSA research (see footnote 20) with anomalies simulating wall loss under combined longitudinal and hoop loadings.

Construction:

8) **Girth Welding Procedure Qualifications:** Girth welding procedures that qualify to meet 49 CFR § 192.225 must address:

a) Weld Procedure Tests:

i) All-weld metal tensile tests must be performed according to Appendix C of "Background of All-Weld Metal Tensile Test Protocol, Final Report 277-T-02," reference: http://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=225. For girth welds utilizing standard 30 degree pipe end bevels, the largest practical diameter round bar tensile specimen which fits inside the weld cross-section may be used. Plastically deforming the pipe segment (e.g. flattening) before removal of the tensile test specimen is not allowed. In

[20] PHMSA has an on-going research project on the effects of anomaly wall loss under combined pipeline loadings. The project is titled "Strain-Based Design and Assessment of Segments of Pipelines with and without Fittings" and is being conducted by the Center for Reliable Energy Systems. The project web link is: https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=556/.

cases where it is not feasible to perform PHMSA all weld metal tensile tests due to the pipe size, then all weld metal tensile tests shall be performed using traditional round bar specimens or transverse all weld tensile specimens in accordance with DET NORSKE VERITAS (DNV) standard, DNV-OS-F101, Submarine Pipeline Systems, October 2010.

ii) Hardness test

iii) Weld metal/Heat Affected Zone (HAZ) fracture toughness tests, such as, where appropriate, Charpy V-Notch impact, CTOD, SENB, SENT, curved wide plate, and full scale tests. The tests must be conducted in groupings in accordance with the essential variable requirements of API 1104 Annex A[21], including possible variations of welding parameters such as heat input in field welding and material property variations resulting from all pipe sources including, but not limited to, chemical compositions and steel rolling temperatures, including their effects on yield and tensile strengths and elongations. Toughness tests must include initiation resistance and/or ductile tearing resistance, ductile-to-brittle transition temperature of the weld metal and heat affected zones. Strain aging from field girth weld coating could reduce the toughness of the weld and HAZ. The effects of strain aging must be considered in specimen preparation and test procedures.

iv) Tensile strength mismatch (minimum weld metal strength must ensure tensile strength overmatch).

b) Weld high-low misalignment parameters must be defined and addressed in full-scale tests, finite element models, or a combination of the two methods.

c) Weld flaw acceptance criteria and Non-Destructive Testing (NDT) criteria:

i) Weld flaw acceptance criteria listing imperfection sizes, lengths, and depths, using automated ultrasonic testing (AUT) which includes sizing error allowance and flaw interaction rules.

[21] API Standard 1104, "Welding of Pipelines and Related Facilities," 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008) or the appropriate § 192.7 referenced edition.

   ii) The flaw acceptance criteria must be consistent with the requirements of weld strain capacity in the life cycle of the pipeline and Conditions 5, 6, and 7.

d) Procedures for repair welding must be developed in accordance with the requirements of API 1104 and the strain capacity during the entire life cycle of the pipeline. The impact of repairs on material properties, such as tensile, toughness, and ductility, from repair thermal cycles must be considered. The post-repair properties must be used in evaluating the girth weld strain capacity if those properties are inferior to the properties of the original welds. For instance, possible toughness degradation in the intermixed zone[22] must be considered. Procedures and limits on repairs must be specified and technically justified.

e) Expanded Weld Procedure Qualification (WPQ) requirements for SBD:

   i) All SBD welding procedures (pipeline procedures, tie-in procedures and repair procedures) must be subject to expanded WPQ testing over the range of welding parameters expected during construction to demonstrate procedure robustness and consistency.

   ii) Mechanized weld procedures must be qualified and fully tested at both High Heat Input and Low Heat Input.

   iii) Manual weld procedures must be qualified over the full range of Heat Inputs anticipated during Construction. During WPQ the Average Voltage & Current must be measured. The number of weld passes must also be recorded.

f) WPQ Consistency Program:

   i) As part of WPQ, a Consistency Program must be conducted for all mechanized weld procedures in which a minimum of five (5) consecutive girth welds must be made to SBD Engineering Critical Assessment (ECA) flaw acceptance criteria or Workmanship criteria, whichever is more restrictive.

[22] The intermixed zone is the weld metal repair area transition zone to the existing girth weld and base material areas.

ii) The girth welds fabricated for the Consistency Program must include a minimum of two (2) welds at Low and High Heat Input and one (1) weld at Nominal Heat Input.

g) Welder Training:

i) Mechanized welding – Every welder / pair of welders must be permitted a minimum of five (5) Welds for Training. Following training, the welder / pair of welders must make a test weld to SBD ECA flaw acceptance criteria or Workmanship criteria, whichever is more restrictive.

ii) Manual Welding – Every welder must be permitted a minimum of one (1) practice weld followed by a single test weld. The testing must include NDE plus API Standard 1104 Main Body destructive test. Re-tests must be permitted for Nick Break tests.

iii) Welder Training and Procedure Qualification (Mechanized and Manual Welding) must be performed during every seasonal start-up or six (6) months of "no welding".

9) <u>Construction Quality</u>:

a) The spacing between any two girth welds must not be smaller than 3D (3 pipe diameters) for pipeline welds and not be smaller than 1D (1 pipe diameter) for transition welds in bends[23].

b) No welded sleeve or composite sleeve repair is permitted during new pipe construction**.**

c) A measurement and monitoring system must be developed and implemented to quantify the pipe ovality, out-of-roundness, and pipe wall thickness prior to and during construction.

d) A measuring system for girth weld misalignment must be developed and implemented for all girth welds to record the misalignment throughout pipe welding.

[23] DGLLC has the option of submitting to PHMSA a procedure for pipe minimum pup length for girth welding to take the place of this condition.

i) The misalignment must be measured and documented at a frequency no less than one (1) data point per one o'clock position or 6 inch of circumference, whichever gives the smaller circumferential spacing.

ii) Procedures for remediating girth welds outside specified misalignment limits must be developed. Alternatively, if misalignment is greater than the maximum allowed, the weld must be cut-out or the strain capacity of the pipe segment where the subject weld is located must be lowered based upon the measured misalignment using the ECA approach of Condition 7.

e) Longitudinal stress and strain during construction must be calculated based upon the anticipated pipe ditch installation procedure. Pipe lifting and lowering-in practices, ditch depths, lift heights, number of lift points, and spacing between lift points must be specified.

i) Pipe lowering-in stress and strain analysis must consider the total transition length – that is, all pipe joints between the touch-down point at the bottom of the trench and the touchdown point on the leading end of the pipe string. Both vertical profile and horizontal offset from pipe support to the center of the ditch must be technically considered.

ii) Lifting practices must assure that the radius of curvature of the pipe during lifting will not overstress the pipe and girth welds.

10) **Girth Weld Testing During Production Welding:** DGLLC must implement a program to confirm on-going quality for usage of strain based design. The program must be addressed in the ***SBD Plan***, which must be reviewed by an independent third party engineering expert/firm and PHMSA as per Condition 3(b).

a) Increased Quality Assurance / Quality Control (QA/QC).

i) Production welding must be performed within the range of welding parameters of those qualified.

ii) A comprehensive QA/QC program must be established to record and monitor the welding parameters during production welding on a real time basis to ensure that production welds are made within the welding parameter tolerances qualified during WPQ.

a. Any weld that is made outside the range of qualified parameters, such as those made outside the Qualified Heat Input Range (as measured by the electronic recording equipment), must be rejected and 'cut out'.

b. Electronic measurement spikes, while not common, do occur; however these anomalous spikes will not automatically trigger a 'cut out'. The spikes must be evaluated on a case by case basis.

iii) QA/QC staff and independent inspectors must be trained and qualified prior to inspecting production welding.

b) Start-up Weld Consistency Requirements prior to Full Production

i) Weld consistency at start-ups, including seasonal start-ups and shut downs due to high repair rates, must consider staggered production where weld quality is evaluated over a limited number of welds; and

ii) Only when weld repair rates achieve an acceptable level[24] can the Contractor resume full production.

11) **Girth Weld Identification:** Each girth weld and pipe joint must be uniquely identified and traceable to:

a) Weld history records including, but not limited to: weld procedure used, weld repair procedure used, weld identification, welder(s) name(s), weld rod or wire, and date of weld;

b) Identification of weld procedure specification (WPS) and procedure qualification record (PQR);

c) Non-destructive test (NDT) history including, but not limited to: NDT procedure used, weld/NDT identification, results of NDT, NDT technician (Level II), NDT technician (Level III) and date of NDT; and

d) Coatings and any other post-weld processes applied to the weld.

12) **Deformation Tool:** DGLLC must run a high resolution deformation tool through all ***SBD Segments*** not later than the end of ***Pipeline Start-Up*** (see Condition 26, "Nomenclature") and remediate, as required, all expanded pipe in accordance with PHMSA's "Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength" dated September 10, 2009.

[24] Weld repair rates over 10 percent would be deemed high repair rates at seasonal start-ups.

13) **<u>Grounding and Cathodic Protection</u>:** Interference current protection and cathodic protection must be provided for all buried ***SBD Segments*** within one (1) year of installation of the pipeline in the ditch (including backfill) to meet 49 CFR §§ 192.328(e), 192.620(d)(5) through (8) and Condition 19. Interference currents to be mitigated include:

a) induced alternating current (AC) and fault current protection from overhead AC transmission lines;
b) telluric currents (geomagnetic earth currents); and
c) all other sources of direct current (DC) or earth currents.

During the commissioning of the cathodic protection systems and during the annual cathodic protection surveys, DGLLC must test for the presence of interference currents and areas with insufficient levels of cathodic protection that could materially impact pipe reliability. Should such conditions be detected, then DGLLC must take remedial action within one (1) year of detection, whether through effective cathodic protection, additional grounding, or other technically viable means. The interference current protection and cathodic protection system may be temporary or permanent, but in all cases, one or more of the applicable criteria contained in Appendix D of Part 192 must be achieved and maintained. Both the interference protection and cathodic protection systems must include provisions for testing and monitoring the performance of the systems including provisions for measuring polarized pipe-to-soil potentials and AC coupons, as a minimum.

14) **<u>Right-of-Way Construction Monitoring Program</u>:** A right-of-way monitoring program must be developed and implemented for all pipeline ***SBD Segments*** during all construction phases based upon the progress of construction. The right-of-way construction monitoring program must include provisions for:

a) periodic collection of soil and groundwater samples to test for chemical and electrical properties related to pipe corrosion, where technically applicable;
b) quality assurance for bedding and backfill materials;
c) quality assurance for main line pipe and girth weld coatings (above ground and below ground), including horizontal directional drill (HDD) coating quality; and

d) where the pipeline is parallel to overhead alternating current (AC) transmission lines, AC pipe-to-soil potentials and AC current densities must be measured periodically and supplemental grounding provided, where necessary, to assure safe conditions.

Observed field conditions that can have an integrity impact on pipeline operations and integrity management plans must be documented during construction.

Operations and Maintenance (O&M):

15) **Conditions for Start of Service:** Conditions 4 through 14 above (except Condition 12) must be implemented prior to placing the pipeline in natural gas service. The implementation of Conditions 4 through 14 must be included in the DGLLC Operations & Maintenance (O&M) Procedures if they apply to O&M.

16) **O&M Procedures:** In addition to O&M procedures otherwise required by 49 CFR Part 192, the DGLLC O&M Procedures must address all operating parameters that have an effect on the implementation for compliance with any of these ***SBD conditions***, including but not limited to maximum and minimum pressures, pipe corrosion, gas and environmental temperatures, gas quality, and the following:

a) The effects of corrosion anomaly (defects) on the strain capacity of the pipe and girth welds must be considered. The anomaly interaction criteria of a minimum of 6*t, with t being the pipe wall thickness*, must be used for longitudinal and circumferential wall loss.[25]

b) Determination of the nature, growth parameters, and location of all strain demand events (e.g., frost heave, thaw settlement, seismic, geologic fault areas, soil liquefaction areas, or soil movement areas).

c) Determination of strain capacity and strain demand along the ***SBD Segments*** in accordance with design and material specifications and tests for key parameters (as determined in Conditions 5, 6 and 7) including as appropriate:

i) Pipe wall thickness,

ii) Pipe tensile properties,

iii) Weld tensile properties,

[25] Other anomaly interaction criteria may be used if it is more conservative than the required criteria.

iv) Weld hardness, including weld metal and HAZ,

v) Weld toughness,

vi) Pipe dimensional tolerance,

vii) Girth weld high-low misalignment,

viii) As-built girth weld nondestructive test (NDT) acceptance flaw size,

ix) Allowance for flaw growth if ductile tearing limit state is used in determining the tensile strain capacity[26],

x) Manufacturing, construction and operational inspection plan for ***SBD Segments***, and

xi) O&M procedures and life cycle implementation plan for ***SBD Segments***.

d) Develop and implement strain demand monitoring systems including In-line Inspection tools as specified in Condition 17, and/or real-time, on-location monitoring procedures and methods to verify the reliability and accuracy of these procedures. The strain demand monitoring systems must be technically justified for estimation of actual strain (tensile, compressive, and combined) demand levels. The strain demand from the monitoring systems must have the comparable level of accuracy and resolution as the strain capacity so the strain demand can be compared consistently to the strain demand limit. When strain demand magnitude greater than 0.5% is expected, the pipeline must be monitored or remediated in accordance with integrity remediation measures specified in Condition 17.

e) Develop and implement material properties surveillance procedures for any time-dependent degradation mechanisms found during material testing, construction, or on-going operations that may affect SBD.

17) <u>Monitoring and Determination of Pipeline Strain Demand</u>:

a) Devices or processes of strain demand monitoring must be installed or implemented either during construction (e.g., fiber optical cable, strain gages, etc.), or during operation (inertial measurement unit (IMU), ground survey, aerial survey), when locations of high strains are discovered after the pipeline is put in service. When the

[26] O&M plan must ensure that the flaw growth in the life cycle of the pipeline is less than the critical flaw growth in the ductile tearing limit state. It is necessary to demonstrate that the flaw growth can be accurately and consistently measured if the allowance for flaw growth were to be given.

monitoring is not directly on the pipeline, appropriate soil and pipe interaction models must be used to calculate the strains imposed on the pipe.

b) The resolution of the strain demand monitoring devices and processes must be consistent with that required to accurately determine strains up to the magnitude of the strain capacity as determined in Condition 7. Tool inaccuracy is addressed in Condition 17(g)(iii).

c) DGLLC strain demand monitoring procedures must take into account the limitations and accuracy of the strain measurement. If monitoring devices have directional or accuracy limitations that cannot be compensated for through tolerances and safety factors in the procedures, multiple devices, or processes for monitoring must be used.

d) Data acquisition and analysis must be of a frequency to ensure the strain demand limit is not exceeded before mitigation measures can be implemented. The frequency of monitoring may be adjusted based on the site-specific strain growth rate calculations with safety factors using procedures that have been reviewed by PHMSA with "no objection". PHMSA may request an independent third party engineering expert/firm review of the procedures and findings.

e) Whenever high strain conditions are identified, DGLLC must evaluate the site-specific strain demand limit. For the strain demand limit evaluation, the site-specific data must include actual pipe geometry, stress-strain data, Y/T ratios, construction weld records, NDE results and other recorded data that affect the strain capacity as given in Condition 7. The appropriate safety factor, as given in Condition 6, must be applied to obtain the site-specific strain demand limit from the site-specific strain capacity. In lieu of site-specific data, the strain demand limit can be established based on the material, geometry, and weld records of the entire ***SBD Segment*** that would result in a more conservative strain demand limit than the site-specific strain demand limit.

f) Whenever high strain conditions are identified, DGLLC must evaluate the site-specific strain demand. For the strain demand evaluation, the site-specific geotechnical data must include burial depth, soil type and subsurface temperature information, water table height, and other recorded data that contribute to the evaluation and understanding of strain demand and growth of strain at this location.

The site-specific strain demand model must be calibrated and validated by physical measurements, such as strain gages and/or geospatial mapping.

g) The conditions for geospatial mapping, i.e., IMU, are given below as an example of a strain demand monitoring method. The principles of mapping are applicable to other monitoring methods when appropriate.

    i) Geospatial Pipeline Mapping: Multi-dimensional geospatial pipeline mapping inline inspection (Mapping ILI) tools must be run through all ***SBD Segments***. The Mapping ILI tools must be capable of mapping the pipeline location based upon: plan, elevation, and distance. The Mapping ILI tools must be capable of mapping features such as: pipeline alignment, direction and orientation of horizontal and vertical with respect to angle, radius, direction and location. The Mapping ILI tools (1) must have sufficient accuracy to ensure accurate and timely usage of engineering critical assessment (ECA) and Operations & Maintenance (O&M) procedures for SBD and (2) are capable of identifying and locating high strain conditions with a 90% probability of detection of the strain demand in Condition 17. Conditions that can cause additional stresses or strains on girth welds, but not measureable from geospatial mapping tools, must be technically considered in the weld integrity evaluation.

    ii) The Mapping ILI tool must be run not later than the end of ***Pipeline Start-Up*** and once each calendar year not to exceed fifteen (15) months thereafter. Alternatively, after the first three (3) Mapping ILI tool runs, the timing of future tool runs may be determined by comparing the rate of increase in site-specific strain demand with the remaining margin between site-specific strain demand and site-specific strain demand limit. The justification for any alternative interval must be provided to PHMSA Director, Western Region, or PHMSA project designee, for review and DGLLC must receive a "no objection" from PHMSA prior to extending Mapping ILI tool run interval.

    iii) All Mapping ILI tool measurements must have a tool inaccuracy (tolerance) factor, as appropriate for the ILI tool, added to all strain demand calculations.

h) DGLLC must report and remediate high strain conditions as specified in the table "Pipeline Segment Onsite Strain Demand Monitoring" below[27].

Pipeline Segment Onsite Strain Demand Monitoring				
Strain Demand Magnitude that Triggers Action		**Action Required**	**Minimum Density of Monitoring Locations**	**Frequency of Data Collection[28]**
Level	**Strain Demand**			
1	Greater than 0.5% longitudinal strain and less than 75% of strain demand limit	Monitor	One per every 10 joints of pipe	Once every six (6) months, or earlier based upon growth rate calculations [29]
2	Equal to or greater than 75% of strain demand limit and less than 90% of strain demand limit[30]	Monitor. Develop site specific strain growth rate and corresponding remediation plan to ensure strain demand limit is not reached during Operational Life. The remediation plan must be implemented within one (1) year of the date of discovery, or prior to the date when the strain demand limit is expected to be exceeded, whichever is sooner.	One per every 2 joints of pipe	Once every three (3) months, or earlier based upon growth rate calculations [31]

[27] This table "Pipeline Segment Onsite Strain Demand Monitoring" assumes that the strain demand limit is no less than 0.67%. If the strain demand limit is less than 0.67%, the *SBD Plan* must be reviewed jointly by DGLLC, PHMSA. PHMSA may request a third party engineering expert/firm review. Monitoring levels must have a "no objection" from PHMSA Director, Western Region, or PHMSA project designee.

[28] Data collection must not be less than the frequency noted in this table without a notice and safety justification to PHMSA prior to this time interval and a "no objection" from PHMSA Director, Western Region, or PHMSA project designee.

[29] All growth rate calculations used for data collection must have a safety factor that takes into account integrity, engineering, and operational findings. DGLLC may decrease this frequency review to annually, not to exceed 15 months, with a "no objection" from PHMSA Director, Western Region, or PHMSA project designee. PHMSA may request an independent third party engineering expert/firm review. The procedure must designate the "site specific areas" that may be increased to annually, not to exceed 15 months.

[30] The strain demand limit used in this table must have a safety factor as defined in Condition 6. Level 2 and 3 evaluations can be based upon the "site-specific strain demand limit" for the pipeline section (footage).

[31] DGLLC may decrease this frequency review to every six (6) months, not to exceed 7½ months, with a "no objection" from PHMSA Director, Western Region, or PHMSA project designee. PHMSA may request an independent third party engineering expert/firm review. The procedure must designate the "site specific areas" that may be increased to every six (6) months, not to exceed 7½ months.

Pipeline Segment Onsite Strain Demand Monitoring				
Strain Demand Magnitude that Triggers Action		**Action Required**	**Minimum Density of Monitoring Locations**	**Frequency of Data Collection**[28]
Level	**Strain Demand**			
3	Equal to or greater than 90% of strain demand limit	Report to PHMSA Regional Director within 5 days of discovery. Develop remediation plan with PHMSA within 30 days of discovery. The remediation plan is to be implemented within 1 year of the date of discovery, or 90 days prior to the date when the strain demand limit is expected to be exceeded, whichever is sooner.	One per every 1 joints of pipe	Once every one (1) month or earlier based upon growth rate calculations, until remediation is complete.

18) **Coating Disbondment and Cathodic Protection Current:** Within a ***SBD Segment*** where ILI results indicate a wall loss greater than 20%[32] and the strain exceeds a magnitude of 0.5%, DGLLC must take remedial action to address the condition of the coating system, the level of cathodic protection, and to mitigate the corrosion that has occurred. Within one (1) year of the ILI tool run and subsequent data analysis identifying the wall loss, DGLLC must:

   a) Remediate areas greater than 20% wall loss[33] or
   b) Use technologies to demonstrate that adequate levels of cathodic protection are being afforded to the pipeline and that coating degradation or disbondment is limited to the area in question and that the detected wall loss combined with the detected strain levels will not reduce the pipe hoop strength capacity below that required for pressure containment (see Condition 7).

19) **Interference Currents Control:** DGLLC must address induced alternating current (AC) from parallel electric transmission lines, foreign or nearby pipelines, telluric currents, and other interference issues such as direct current (DC) in the ***SBD Segments*** that may affect

[32] Anomalies greater than 20% wall loss up to 40% wall loss may be allowed in segments with strains over 0.5% strain, but must be evaluated with O&M procedures that are based upon a destructive test program and finite element evaluation that validates the procedure.

[33] Anomalies greater than 20% wall loss up to 40% wall loss may be allowed in segments with strains over 0.5% strain, but must be evaluated with O&M procedures that are based upon a destructive test program and finite element evaluation that validates the procedure.

the pipeline. An induced AC or DC monitoring program and remediation plan to protect the pipeline from corrosion caused by stray or interference currents must be in place within one (1) year of the ***SBD Segment*** pipe being installed in the ditch (including backfill).

a) DGLLC must take readings at each alternating current (AC) mitigation test coupon location once every calendar year throughout the life of the pipeline. DGLLC must also take 24 hour recordings of AC interference voltages at 20 % of the AC interference coupon test stations each calendar year. If there are any significant changes in the amount of electrical current flowing in any of the co-located high voltage alternating current (HVAC) power lines, such as from additional generation, a voltage up rating, additional lines, or new or enlarged substations, DGLLC must perform an AC interference survey along the entire co-located pipeline right of way within twelve (12) months of such change. DGLLC must evaluate interference areas where AC current discharge is greater than 20 Amperes per meter squared with the most recent metal loss ILI tool results to determine if remediation measures are warranted. DGLLC must remediate any interference causing AC current discharge greater than 50 Amperes per meter squared of pipe surface within twelve (12) months of the AC interference survey.

b) At least once every seven (7) calendar years not exceeding 84-months, DGLLC must perform an engineering analysis on the effectiveness of AC, DC, telluric current, and other electrical interference mitigation measures and must evaluate any AC interference causing AC current discharge greater than 20 Amperes per meter squared of surface area. In evaluating such interference, DGLLC must integrate AC and all other electrical interference data with the most recent metal loss ILI tool results to determine remediation measures.

c) Within twelve (12) months of the interference engineering analysis, DGLLC must remediate any AC interference causing AC current discharge greater than 50 Amperes per meter squared of surface area. Remediation means the implementation of performance measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any DC interference that results in cathodic protection (CP) levels that do not meet the requirements of 49 CFR Part 192, Subpart I, must be remediated within twelve (12) months of this evaluation.

d) Electrical interference mitigation and cathodic protection systems and equipment must comply with Condition 13.

20) **<u>Data Integration</u>:** DGLLC must integrate and analyze data pertaining to the integrity of the ***SBD Segments***. Data integration must include the following information: all information pertaining to monitoring, compliance, and remediation required by the ***SBD Conditions***, pipe diameter, wall thickness, grade, and seam type; pipe coating including girth weld coating; maximum allowable operating pressure (MAOP); class location (including boundaries on aerial photography); high consequence areas (HCAs) (including boundaries on aerial photography); hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; in-line inspection (ILI) tool results including high resolution (HR) metal loss ILI tools, HR-deformation tools, cathodic protection current measurement, and mapping ILI tool results: close interval surveys (CIS) – all; depth of cover surveys; rectifier voltage and current outputs – past 7 years; cathodic protection test point survey readings – past 7 years; AC and DC interference surveys; telluric current surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; stress corrosion cracking (SCC) excavations and findings; pipe exposures for any reason, geotechnical locations where strain monitoring is on-going with monthly measurements, and each location with a strain magnitude greater than 0.5% identified in accordance with Condition 17. Data integration must be outlined in the project GIS or on pipeline route sheets (example: scale of 1-inch = 100 up to 500-feet on "D (24"x36") or E (36"x42")" size drawings or similar size drawings), with parallel sections for each integrity category and recent ROW imagery (aerial photography or satellite imagery, updated within 24 months of initial in-service and every 7-years thereafter). Data integration must be updated on a continuing basis and with at least a semi-annual review of integrity issues to be remediated.

21) **<u>Treatment of SBD Segments as Covered Segments under Integrity Management Rule</u>:** Notwithstanding the definition of *covered segment*, DGLLC must incorporate the ***SBD Segments*** in its written integrity management program (IMP) and treat the ***SBD Segments*** as a *"covered segment"* in a *"high consequence area (HCA)"* in accordance with 49 CFR Part 192, Subpart O, except for the reporting requirements contained in 49 CFR § 192.945.

a) DGLLC must include the ***SBD Segments*** in its IMP baseline assessment plan in accordance with 49 CFR § 192.905.
b) DGLLC must perform ILI assessment along the entire length of the ***SBD Segments*** using ILI tools (high resolution metal loss, high resolution deformation and mapping) not later than the end of ***Pipeline Start-Up***.
c) DGLLC must perform ILI assessment using all ILI tools described in Condition 21(b) on a maximum seven (7) calendar year interval. These ILI tools may be required to be run individually at more frequent intervals as needed in order to comply with all ***SBD Conditions***.
d) DGLLC must perform a cathodic protection assessment by a protective coating assessment of buried pipe by direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) in accordance with 49 CFR §192.620 along the entire length of the ***SBD Segments*** after pipe construction backfill but within nine (9) months of placing the cathodic protection system in operation.
e) DGLLC must perform an External Corrosion Direct Assessment (ECDA) in accordance with 49 CFR § 192.925 on a maximum seven (7) calendar year interval to evaluate and remediate external pipe coating and cathodic protection operational performance.

22) **<u>Analysis of ILI Tool Data and Discovery of Injurious Anomalies</u>:** In addition to the assessment and repair requirements contained in 49 CFR Part 192, Subpart O, DGLLC must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs and document and justify the values used. DGLLC must demonstrate ILI tool tolerance accuracy for each ILI tool run by use of calibration excavations and unity plots that demonstrate ILI tool accuracy for depth and length within ±10% accuracy for 90% of the time. The unity plots must show: a) actual anomaly depth versus predicted ILI tool depth and b) failure pressure/MAOP for actual anomaly dimensions versus ILI tool predicted failure pressure/MAOP for ILI tool anomaly dimensions. Discovery date must be within 90 days of an ILI tool run for each type ILI tool (high resolution geometry, high resolution deformation or high resolution metal loss). ILI tool evaluations for metal loss must use "6t x 6t" interaction or more conservative criteria for determining anomaly failure pressures and remediation response timing with "6t" being pipe wall thickness times six.

23) **<u>Remediation</u>:** In addition to all assessment and repair requirements contained in 49 CFR Part 192, Subpart O, the following section provides requirements for excavation, investigation, and remediation of anomalies based on ILI tool data results in accordance with 49 CFR §§ 192.485 and 192.933, and must incorporate the appropriate class location design factors in the anomaly repair criteria for the ***SBD Segments***. Reassessment by ILI tool must reset the timing for anomalies not already investigated and/or repaired. DGLLC must evaluate ILI tool metal loss data by using appropriate assessment analytical tools that incorporate the effects of longitudinal strain on the pressure containment capacity of the pipeline. Such tools may be developed by using three-dimensional finite element analysis with the full range material properties, anomaly dimensions, and interaction of multiple anomalies and the final analytical tool may be a finite element procedure for use in ECA. Established tools, such as ASME Standard B31G, "*Manual for Determining the Remaining Strength of Corroded Pipelines*" (ASME B31G), the modified B31G (0.85dL) or R-STRENG[34], may be used provided that (1) the effects of longitudinal strain are technically considered/implemented and (2) the safety of the tool is equivalent or greater than that established for assessing pipelines under traditional stress-based design (longitudinal strain magnitude less than 0.5%). The ILI tool results must address ILI tool tolerances, unity charts findings, and corrosion growth rates of anomalies.

a) <u>Immediate response</u>: Any anomaly within a ***SBD Segment*** that meets either: (1) a Failure Pressure Ratio (FPR)[35] equal to or less than 1.1; or (2) an anomaly depth equal to or greater than 60% wall thickness loss.

b) <u>One-year response:</u> Any anomaly within a ***SBD Segment*** in Class 1 location pipe that meets either: (1) an FPR equal to or less than 1.39[36]; or (2) an anomaly depth equal to or greater than 40% wall thickness loss.

[34] RSTRENG: John F Kiefner and Pat H Vieth, *A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe*, Contract PR-3-805, Prepared for the Pipeline Corrosion Supervisory Committee Pipeline Research Committee of Pipeline Research Council International, Inc. by Battelle Memorial Institute, December 22, 1989.

[35] Failure Pressure Ratio means the predicted failure pressure divided by MAOP.

[36] When the anomaly is in a class 2 location use a FPR of 1.67 and when the anomaly is in a class 3 or Class 4 location use a FPR of 2.00.

c) Monitored response: Any anomaly within a ***SBD Segment*** with a Class 1 location pipe that meets both: (1) an FPR greater than 1.39[37]; and (2) an anomaly depth less than 40% wall thickness loss. The schedule for the response must take tool tolerance and corrosion growth rates into account.

If factors beyond DGLLC's control prevent the completion of any evaluation or implementation of any remediation measure or plan required under this Condition or Conditions 17 through 22 within the time period specified, the completion of the evaluation or implementation of the remediation measure or plan must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date that the evaluation will be completed or remediation measure or plan implemented must be submitted to the PHMSA Director, Western Region or PHMSA project designee no later than one (1) month prior to the end of the time period specified under the applicable Condition. Any extended evaluation or remediation schedule submitted to PHMSA from DGLLC must receive a "no objection" from the PHMSA Director, Western Region or PHMSA project designee.

Reporting and Certification:

24) **Reporting:** Within twelve (12) months following Pipeline Start-Up and annually[38] thereafter, DGLLC must report the following to the PHMSA Director, Western Region with copies to the Director, PHMSA Engineering and Research Division, and Director, PHMSA Standards and Rulemaking Division[39].

a) In the first annual report, DGLLC must describe the economic benefits of the ***SBD Conditions***. Subsequent reports must indicate any changes to this initial assessment.

b) In the first annual report, fully describe how the public benefits from energy availability. Subsequent reports must indicate any changes to this initial assessment.

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[37] When the anomaly is in a class 2 location use a FPR of 1.67 and when the anomaly is in a class 3 or Class 4 location use a FPR of 2.00.

[38] Annual reports and other reports submitted to PHMSA must be provided as per regulations.

[39] Upon notice to DGLLC, PHMSA may update reporting contacts for Condition 24.

c) The number of new residences, identified sites, or other structures intended for human occupancy and public gathering areas built within the ***SBD Segment's*** potential impact radius (PIR) as defined in 49 CFR § 192.903.

d) Any integrity threats identified during the previous year and the results of any ILI or direct assessments performed during the previous year (such as strains over 0.5% and anomalies over 20% wall loss) in the ***SBD Segments***.

e) Any reportable incident or any leak reported on the DOT Annual Report.

f) All repairs on the pipeline that occurred during the previous year in the ***SBD Segments***.

g) Any on-going damage prevention, corrosion, and longitudinal strain preventative initiatives affecting the ***SBD Segments*** and a discussion of the success of the initiatives.

h) Annual data integration information, as required in Condition 20 - Data Integration.

i) All actual strain demand conditions that exceed the 0.5% Level 1 strain demand limit specified in Condition 17.

j) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.

25) **Certification:** A senior executive officer, vice president or higher, of DGLLC must certify in writing the following:

a) DGLLC pipeline ***SBD Segments*** meet these ***SBD Conditions***;

b) The written manual of O&M procedures for the DGLLC pipeline includes all applicable requirements in 49 CFR Part 192 and these ***SBD Conditions***; and

c) DGLLC must send the certifications required in Condition 25(a) through (b) with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Western Region; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division within three (3) months of placing the pipeline into gas service. DGLLC must provide a status update, including any proposed changes to the final ***SBD Plan*** as per Condition 3(a), within six (6) months after placing the pipeline into gas service.

Nomenclature:

26) **Nomenclature:** Defines technical terms used for strain based design throughout these ***SBD Conditions***.

   a) Strain Based Design (SBD): Strain based design (SBD) is a pipeline design methodology with specific goals of providing safe and reliable service when such a pipeline is subjected to longitudinal strains with magnitudes greater than 0.5%. It does not replace design requirements based on the maximum hoop stress criteria of 49 CFR 192.

   b) Strain demand: Strain demand is the longitudinal strain imposed on a pipeline by its surrounding environment (e.g., frost heave, thaw settlement, seismic, geologic fault areas, soil liquefaction areas, or soil movement areas) as outlined in Condition 6(b).

   c) Strain demand limit: Strain demand limit is a specific longitudinal strain demand value that cannot be exceeded. The strain demand limit must be less than the strain capacity. The difference between the strain capacity and strain demand limit is a part of the safety margin in a SBD approach (see Condition 6(a)). The strain demand limit must be established for the ***SBD Segments*** in accordance with Condition 6.

   d) Site-specific strain demand: Site-specific strain demand is the strain demand specific to a particular pipeline site within the ***SBD Segment***. Site-specific conditions contribute to the site-specific strain demand, including local operational parameters, local soil conditions, pipe material and geometric features, and pipe/soil interaction. The strain demand profile varies over the length of the strain feature and values can be established at distinct locations, e.g., pipe body and individual girth weld locations.

   e) Site-specific strain demand limit: Site-specific strain demand limit is the strain demand limit specific to a particular pipeline site within the ***SBD Segment.*** Site-specific conditions contribute to the site-specific strain demand limit, including material conditions and weld imperfections.

   f) Strain capacity: Strain capacity is the longitudinal strain limit of a pipe and/or girth weld at the point of an incipient failure event, such as a leak or rupture with accompanying loss of pressure containment, loss of structural stability, or features that have long-term negative consequences.

g) Tensile strain capacity: Tensile strain capacity (TSC) is the maximum longitudinal tensile strain the pipe and/or girth weld can withstand without loss of pressure containment.

h) Compressive strain capacity[40]: Compressive strain capacity (CSC) is the maximum longitudinal compressive strain when the pipe segment reaches its maximum bending moment under lateral bending or its maximum compressive load under compression.

i) Uniform strain: Uniform strain is the engineering strain corresponding to the ultimate tensile strength in an engineering stress vs. engineering strain plot.

j) Small-scale testing: Typical small-scale testing includes uniaxial tension test, uniaxial compression test, single edge notched bending (SENB) test, single edge notched tensile (SENT) test, and Charpy V-notch (CVN) impact test. The dimensions of typical small-scale test specimens range from a few inches to tens of inches. The specimens are usually light enough that they can be handled without the use of lifting equipment.

k) Medium-scale testing: A typical medium-scale test is a curved wide plate (CWP) test. The test specimen is a curved piece of pipe with a nominal gauge width of 200 mm (8 inch) to 450 mm (18 inch) and a nominal length of 4-5 times of the gauge width. The specimen usually has a girth weld in mid-length and is pulled in the longitudinal direction. A machined notch or fatigue-sharpened flaw is usually placed in the weld or heat-affected zone to simulate welding defects.

l) Full-scale testing: A full-scale test involves a full-size pipe with no portions of the pipe circumference cut out. The test may be performed with or without internal pressure. The pipe can be loaded in longitudinal tension, longitudinal compression, lateral bending, or combination thereof.

[40] Reaching CSC generally does not lead to immediate loss of pressure containment if the pipe is restrained from further deformation. The consequence of exceeding CSC varies, depending on the mechanical properties of the pipe and welds, site-specific support conditions, and operational conditions of the pipeline. During the DGLLC Material Testing Program the CSC will be reviewed and an alternative evaluation may be proposed by DGLLC. Any alternative definition of CSC must be reviewed with PHMSA and may be incorporated into the draft and final ***SBD Plan*** after obtaining "no objection" from PHMSA. Both immediate and long-term consequence of exceeding the CSC as defined must be evaluated and technically justified. Condition 23 has requirements for the assessment and remediation of dents and wrinkles in accordance with § 192.933, Subpart O.

m) Pipeline Start-Up: An interval during which the pipeline system begins operations and throughput (product flow through the pipeline) is ramped to its commercial capacity. For the purposes of these ***SBD Conditions***, Pipeline Start-Up is defined as a period of no more than one (1) calendar year after the first gas is introduced to the pipeline.

n) Technically considered: A documented engineering and operational technical review of all findings and plans.

o) Independent third party engineering expert/firm: an engineering expert or firm that (1) is retained by mutual agreement between DGLLC and PHMSA and (2) commits to submitting reports and other forms of communication simultaneously to DGLLC and PHMSA.

Limitations:

PHMSA grants this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether DGLLC has complied with the specified conditions of this special permit.
2) Failure to submit the certifications required by Condition 25 within the time frames specified may result in revocation of this special permit.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require DGLLC to comply with the regulatory requirements in 49 CFR §§ 192.103, 192.105, 192.111, 192.317, and 192.619. As provided in 49 U.S.C. § 60122, PHMSA may also issue an enforcement action for failure to comply with this special permit.
4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify DGLLC in writing of the proposed action and provide DGLLC an opportunity to show cause why the action should not be taken. In accordance with 49 C.F.R. § 190.341(h)(3), if necessary to avoid the risk of significant harm to persons, property, or the environment, PHMSA will not give advance notice and will declare the proposed action (revocation, suspension, or modification) immediately effective.

5) The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit in accordance with 49 CFR § 190.341(h)(4).
6) If DGLLC sells, merges, transfers, or otherwise disposes of the assets known as the ***SBD Segments***, DGLLC must provide PHMSA with written notice of the transfer within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances pursuant to 49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under 49 CFR § 190.341(h)(1).

Appendix A - Pipe

DGLLC must prepare: material specifications, material prequalification, material qualification, inspection and testing plans, production start-up tests, and start-up certificate tests using Appendix A[41].

The DGLLC Pipeline will be constructed of line pipe meeting the requirements of API 5L Grade X-52.

1) Materials Specifications for Pipe
    a. Full stress-strain curves in both the hoop and longitudinal directions must be provided. The minimum longitudinal yield strength (both tensile and compressive) defined at 0.5 % engineering strain, must be ≥ 90 % of the specified minimum yield strength (SMYS) in the hoop tension direction. The maximum yield strength to ultimate tensile strength (YS/UTS) ratio must be ≤ 0.90 (both before and after simulated coating). Hoop tensile properties must be established by testing specimens without flattening including round-bar specimens. Longitudinal tensile properties must be established by testing full thickness strap specimens.
    b. The longitudinal tension tests must be conducted both prior to and after simulated coating. (Coating may be simulated by ageing the test specimen at a temperature equal to the lesser of 250°C, or the maximum temperature experienced during FBE coating, for five (5) minutes).
    c. The longitudinal stress-strain curves in the "as received" condition (i.e., not aged) must exhibit "round house" (continuous yielding) behavior, i.e., no Lüders plateau of more than 0.2% strain.
    d. The stress-strain curves in the "aged" condition should ideally exhibit "round house" (continuous yielding), but if discontinuous yielding is exhibited the Lüders

[41] Appendix A is intended to ensure consistent material properties are used throughout the DGLLC pipeline for material testing, strain capacity modeling, welding procedures, and strain demand limits. Any changes to the material specifications used on the DGLLC ***SBD Segments*** that are not in accordance with this Appendix A must be submitted to PHMSA Director, Western Region or PHMSA project designee for review and "no objection" prior to usage. Appendix A changes are not intended as being a change that would subject the special permit to be publicly noticed.

plateau elongation must be < 0.5 %, i.e., the length of the plateau from initial yielding must be < 0.5 %.

e. If the value of "Young's Modulus" estimated by the test is not within ± 15 % of the theoretical value as per ASME B31.8 (Table 832.5-1) the test must be discarded. The sources of the deviation from theoretical values must be identified. It is necessary to confirm that the non-discarded data are free of the influence of the identified sources.
f. The longitudinal tension specimen must exhibit uniform strain (elongation at maximum load) of > 6 %.
g. The maximum longitudinal tensile yield strength must be SMYS + 17.4 ksi (120 MPa).
h. The minimum compressive longitudinal yield strength must be ≥ 90 % of SMYS.
i. The drop weight tear test (DWTT) specimen taken 180 degrees from the weld must exhibit > 85 % shear at the lowest temperature under normal operations or LAST (Lowest Anticipated Service Temperature).
j. The Charpy energy and % shear values for samples taken at mid thickness and 180 degrees from the weld must be specified at LAST.
k. Crack tip opening displacement (CTOD) R curves must be developed as part of the prequalification procedure and during manufacturer's procedure qualification tests (MPQT) or first day of production testing.
l. The pipe must be resistant to heat affected zone (HAZ) softening when welded at a heat input of 72.2 BTU/in (3.0 kJ/mm). The minimum HAZ hardness must be 190 H_v10.
m. The maximum tolerances on pipe diameter, ovality and wall thickness must be in accordance with API 5L PSL 2. Minimum wall thickness must be limited to a minus zero.

2) Prequalification

The pipe manufacturer must produce a minimum 1000 metric tons (MT) of pipe from a minimum of four (4) heats to demonstrate compliance with the specification. A change in any of the essential variables listed in Table A-1 below must require requalification.

Plates for longitudinal seam line pipe must be tested on each corner in accordance with ASME Boiler & Pressure Vessel (B & PV) Code, Section VIII Division 3, “Procedure for Qualifying New Steels”. Coils for manufacture of helical seam line pipe must be tested on both edges and at the extreme head and tail of the coil. The data developed during prequalification must be used to establish the appropriate test locations during production.

Table A-1 Line Pipe Manufacturing Essential Variables

Essential Variables	Parameters
Chemistry	A change in chemistry outside the limits in Table A-2
Steelmaking Method	EAF or BOF
Refining Process	LMF and/or Vacuum Treatment
Casting	Ingot or continuous casting
Slab Reheating Temp. [NOTE 1]	+/– 2.5%
Rolling Practice	Air or Water Cooling (TMCP)
Total Rolling Reduction	+ Unlimited, –15%
Finishing Reduction	+ Unlimited, –15%
Finish Rolling Temp.	+/– 45°F (+/–25°C)
TMCP Water Start Temp. [NOTE 2]	+/– 45°F (+/–25°C)
TMCP Water Stop Temp. [NOTE 2]	+/– 63°F (+/–35°C)
TMCP Cooling Rate	+/– 15%
Plate Manufacturer	Any change in manufacturer or manufacturing location.
Change in Pipe Making Process	From JCOE to UOE to Three Roll Bending or Spiral, etc.
Expansion Ratio	+/– 0.3%
Coating Temp.	+/– 36°F (+/– 20°C)

NOTE 1: Larson Miller Parameter (LMP) = Max T (°K) [20 + log time] hours above threshold.

NOTE 2: Applicable only if accelerated cooling is used.

3) Requalification

A change in steel chemical composition, either ladle or product outside the tolerances shown in Table A-2 must require requalification of the manufacturing procedure (full testing of a minimum of four (4) heats produced as a 1000 metric ton (MT) batch).

Table A-2 Allowable Chemistry Variation

carbon	+0.02, –0.03%
manganese	+/– 0.20%
phosphorus	+0.010%, –no limit
sulfur	+/– 0.005%
silicon	+0.15%, –no limit
copper	+/– 0.15%
nickel*	+0.50%, –0.15%
chromium	+/– 0.10%
molybdenum	+0.04%, –0.06%
niobium	+/– 0.010%
titanium	+/– 0.010%
aluminum	+/– 0.025%
vanadium	+/– 0.02%
boron	+/– 0.0005% (+/–5 ppm)
nitrogen (total)	+0.0025, –0.0045% (+25 ppm, –45 ppm)
CE**	+0.02, –0.03
Pcm	+0.02, –0.03

4) Inspection and Testing Plan (ITP)

a. Testing of Mechanical Properties

i. Tensile Tests

1. Longitudinal tensile test specimen taken from pipe body must be rectangular specimen with full wall thickness. The width within the gauge length of specimen must be at least the pipe wall thickness and the gauge length (over which extensometer is mounted) must be a minimum of twice the specimen width within the reduced gauge section. The reduced gauge section must be a minimum of four (4) times of specimen width. The specimen must be non-flattened during its preparation.

b. Tests and Requirements: The tests and requirements are shown in Table A-3.

c. Quality Assurance and Quality Control Surveillance (QA/QC): Manufacturing QA/QC of pipe production must be conducted in accordance with an ITP approved by DGLLC.

<table>
<tr><th colspan="4">Table A-3 Test and Requirements</th></tr>
<tr><th colspan="2">Items</th><th>Frequency Note 4</th><th>Number, location and orientation of specimen</th></tr>
<tr><td rowspan="7">Pipe Body NOTE 1, 3</td><td>Chemical composition product analysis</td><td>1/heat</td><td>1</td></tr>
<tr><td>Pipe body transverse tensile</td><td>1/lot NOTE 2</td><td>1 (180°, transverse)</td></tr>
<tr><td>Pipe body longitudinal tensile (as received)</td><td>2/lot</td><td>2 (90°, longitudinal)</td></tr>
<tr><td>Pipe body longitudinal tensile (Aged)</td><td>2/lot</td><td>2 (90°, longitudinal)</td></tr>
<tr><td>Charpy impact - pipe body transverse</td><td>1/lot</td><td>3 (180°, transverse)</td></tr>
<tr><td>DWTT</td><td>1/lot</td><td>2 (180°, transverse)</td></tr>
<tr><td>Micrograph</td><td>1/lot</td><td>1 (180°, transverse)</td></tr>
<tr><td rowspan="7">Weld</td><td>Welded joint tensile</td><td>1/lot</td><td>1 (weld, transverse)</td></tr>
<tr><td>Guided root bending</td><td>1/lot</td><td>1 (weld, transverse)</td></tr>
<tr><td>Guided face bending</td><td>1/lot</td><td>1 (weld, transverse)</td></tr>
<tr><td>Charpy impact - weld</td><td>1/lot</td><td>3 (weld, transverse)</td></tr>
<tr><td>Charpy impact - HAZ</td><td>1/lot</td><td>3 (HAZ, transverse)</td></tr>
<tr><td>Micrograph</td><td>1/lot</td><td>1 (weld, transverse)</td></tr>
<tr><td>Vickers hardness</td><td>1/lot</td><td></td></tr>
<tr><td colspan="2">Hydrostatic pressure test</td><td>Each pipe</td><td></td></tr>
<tr><td colspan="2">Hydrostatic burst test</td><td>1 per pipe size</td><td></td></tr>
<tr><td colspan="2">Visual</td><td>Each pipe</td><td></td></tr>
<tr><td colspan="2">Dimension</td><td>Each pipe</td><td></td></tr>
<tr><td colspan="2">NDT</td><td>Each pipe</td><td></td></tr>
<tr><td colspan="2">Start-up test and start-up certificate test</td><td>See Appendix A, Sections 6 and 7 below</td><td></td></tr>
<tr><td colspan="4">NOTE 1: For helical seam pipe the samples must be taken mid-way between the weld seam.
NOTE 2: A lot is defined as 100 pipes, or per heat, or as per API 5L, whichever is less.
NOTE 3: YS/UTS less than or equal to 0.90. Uniform elongation greater than 6%.
NOTE 4: Testing frequency and test type must meet both Table A-3 and API 5L criteria.</td></tr>
</table>

5) Manufacturing and Procedure Qualification Test (MPQT)
    a. MPQT is a test plan for inspection of the steel and pipe rolling processes throughout production of the pipe. It must have defined inspection points throughout the manufacturing process to ensure the steel and pipe specifications are met.
    b. MPQT must include production start-up tests and Start-Up Certificate Test
6) Production Start-Up Tests
    a. Inspection Items - Sampling of ten (10) pipes must be tested for items viii) and ix) below. Two (2) pipes from each heat must be tested for the items (i) through (vii). One (1) pipe from each heat must be subject to supplementary hydrostatic test [item (x) below] at the pressure of 100% SMYS. The pressure must be calculated using specified outside diameter and nominal wall thickness. If the dimension of pipe fails to conform to the requirements of this specification after hydrostatic test, then the following two pipes from the same heat must be selected to perform the same hydrostatic test referenced above.
        i. Chemical analysis;
        ii. Longitudinal and hoop tensile tests (provide full stress-strain curves);
        iii. Charpy impact test (pipe body transverse, weld and HAZ), at the specified temperature;
        iv. DWTT, at the specified temperature;
        v. Vickers Hardness traverse;
        vi. Guided bend test;
        vii. Metallography of pipe body;
        viii. Visual inspection and dimensions;
        ix. Non-destructive inspection;
        x. Hydrostatic test - One (1) pipe from each heat must be tested hydrostatically at the pressure of 100% SMYS. The pressure must be calculated using specified outside diameter and nominal wall thickness. If the dimension of pipe fails to conform to the requirements of this specification after hydrostatic test, then take the following two pipes from the same heat to perform the same hydrostatic test mentioned above at the beginning of this section.

7) Start-Up Certificate Test
   a. Mechanical Properties of Pipe Body
      i. Tensile Test - Tensile tests must be performed on three (3) specimens taken from longitudinal and transverse directions of the pipe body. Full stress-strain tensile curves must be provided.
      ii. Additional tensile tests must be performed on three (3) specimens taken from the longitudinal direction of the pipe body after ageing for five (5) minutes at a temperature equal to the lesser of 482°F (250°C) or the maximum application temperature for the coating of the DGLLC Pipeline. Full stress-strain curves must be provided.
   b. Tests of Pipe Seam Weld
      i. Tensile Test - Tensile testing must be performed on three (3) round bar specimens representing all pipe seam weld metal. Full stress-strain curves must be provided.
   c. Strain Ageing Properties for Pipe (Additional)
      i. Sampling Position of Strain Ageing Test Specimen - The sampling position for the strain ageing test specimen is the same as that of non-aged specimens.
      ii. Condition for Strain Ageing Tests - All tests in 7(c)(iii) must be performed on pipe body specimens after the ageing treatment lasting five (5) minutes at a temperature equal to the lesser of 482°F (250°C) or the maximum temperature experienced during coating under the condition of no pre-strain. In addition, for information only longitudinal tensile tests will be run under the condition of 2% and 5% tensile pre-strain (total strain within gauge length). All specimens must be strained in the longitudinal direction.
      iii. Mechanical Tests After Strain Ageing Test - Longitudinal tensile tests must be performed on three (3) specimens and the full tensile test curve must be provided showing the relationship of displacement and force. For information purposes, complete fracture shear area percentage and Charpy absorbed energy transition curves for transverse Charpy impact

tests must be provided. Tests must be performed in triplicate at a minimum of five (5) test temperatures that cover the ductile to brittle transition temperature range.